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Directive 040

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Pressure and Deliverability Testing Oil and Gas Wells

The Energy Resources Conservation Board (ERCB/Board) has approved this directive on August 9, 2010.

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1 Introduction

Well test information is second only to production data in importance for the prudent management of oil or gas reservoirs. As such, well testing is an integral part of the overall production and depletion strategy of a reservoir. The lowest costs and the most benefit are realized when an appropriate number of high quality tests are run throughout the producing life of the reservoir.

The requirements detailed in this directive are ERCB regulations, as enacted under Sections 7, 11, and 14 of the *Oil and Gas Conservation Regulations*. This directive addresses pressure and deliverability tests, drill stem tests, fluid sampling and analysis, and coalbed methane (CBM) and shale gas control well tests. The well testing requirements defined in this directive are minimum requirements, and the ERCB may require testing that exceeds these requirements where it identifies such a need.

This new version of *Directive 040: Pressure and Deliverability Testing Oil and Gas Wells* is intended to serve as a handbook for testing oil and gas wells. Test quality will improve if licensees/operators use properly trained personnel, and take care in designing, conducting, analyzing, and reporting their tests. The contents of this directive should be useful to anyone involved in testing oil and gas wells, regardless of their level of experience.

To assist licensees/operators in complying with well test requirements, the ERCB offers the following services:

- For access and service in well test matters, contact the Well Test Helpline at welltest-helpline@ercb.ca.
- List of Outstanding Initial Pressure, Deliverability and Unscheduled Tests
  - New list posted monthly, with weekly updates.
  - www.ercb.ca under Industry Zone : Rules, Regulations, Requirements : Well Testing - Pressure Survey Schedules

- Annual Oil & Gas Pool Survey Schedules, complete with current status of fulfillment.
  - Updated once in second & third quarters and monthly afterward.
  - www.ercb.ca under Industry Zone : Rules, Regulations, Requirements : Well Testing - Pressure Survey Schedules
- Information pertaining to electronic data submission, templates for reporting formats, etc.
  - www.ercb.ca under Industry Zone : Rules, Regulations, Requirements : Well Testing

More details on these services are available throughout this directive. Appendix B lists related reference material, and Appendix C lists ERCB Web site and e-mail addresses pertinent to well testing.

1.1 What's New in *Directive 040*

This edition of *Directive 040* includes a clarification of the testing requirements for

- wells producing under Southeastern Alberta Order No. MU 7490 or any successor orders (Sections 3.2, 3.3, 3.6, and 7.1), and
- wells producing gas under the self-declared commingling process (Sections 4.6.10.2 and 7.1).

1.2 How to Use This Directive

ERCB requirements and recommended practices are described within each section and subsection throughout *Directive 040*. "Must" indicates a requirement for which compliance is required and is subject to ERCB enforcement, while "recommends" indicates a best practice that can be used by the applicable party but is not an ERCB requirement and does not carry an enforcement consequence.

2 Regulations Pertinent to Well Testing

Regulations pertinent to well testing are contained in the *Oil and Gas Conservation Regulations*. Section 11.102 provides the authority to set requirements for well testing within this directive. Sections 11.005 and 11.120 require that all tests be submitted.

3 Summary of Basic Minimum Requirements for Well Testing as of December 2006

This section contains the condensed version of the basic minimum requirements for testing oil and gas wells and references the appropriate section for further clarification and explanation. The ERCB may require surveys that exceed these minimum requirements, as it deems necessary.

The well licensee shall comply with the minimum requirements defined below, regarding the conducting and reporting of tests for its gas and oil wells. Any failure to comply with these minimum requirements will result in enforcement action in accordance with *Directive 019*. For annual pressure requirements, the licensee indicated on the ERCB Web site as the coordinating operator will be responsible for compliance with the annual requirements for that pool. For initial pressure and deliverability requirements, submission of drill stem tests, and gas and fluid analysis, the licensee responsibility will also be indicated on the ERCB Web site. Please notify the Well Test Section immediately of any changes in responsibility for fulfilling the well test requirements.

3.1 Test Quality Standards

(See Section 5 of this directive for additional information.)

All tests submitted to fulfill survey requirements must:

- meet the "Acceptable Survey Standards", as defined in Section 5, and
- be reported in the appropriate electronic format defined in Appendix A: WTC PAS File Submission Formats, Business Rules, and Implications for Noncompliance.

More information on electronic reporting is available on the ERCB's Web site www.ercb.ca under Industry Zone : Rules, Regulations, Requirements : Well Testing.

The "Acceptable Survey Standards" for required tests have been translated into business rules and edits which are defined in Appendix A: WTC PAS File Submission Formats, Business Rules, and Implications for Noncompliance.

Some business rules and edits are critical, which will result in the file being rejected. Other edits have been identified as non-critical and will not cause the file to be rejected. The non-critical edits are more subjective, and require some interpretation. They will be administered by an audit process. Tests not meant to fulfill any requirement should be clearly indicated in the Test Data Section of the appropriate PAS file. Setting the [PRPS] = (O)ther will turn-off the "acceptable survey" edits and only be recognized as "information only" data. Whenever possible, the reason for a test being submitted as "information only" should be documented in the [PRGC] (Comment on Pressure) field of the PAS file.

PRPS (**I**)nitial – to be used for initial test requirement fulfillment

PRPS (**A**)nnual – to be used for annual survey requirement fulfillment.

- PRPS] (**O**)ther - submitted only in accordance with Section 11.120 of the *Oil and Gas Conservation Regulations*.

3.2 Initial Pressure Testing Requirements

(See Section 4.2, 4.6.10, and 7.1 of this directive for additional information.)

Initial subsurface pressures are required on productive oil and gas wells as follows

- Gas Wells – on all productive wells, within the first three months of production (one well per pool per section),
- Oil Wells – on all productive exploratory, discovery, development or step-out wells; prior to any sales or production, other than test production (one well per pool per quarter section).

Initial pressures are not required on step-out wells to existing oil pools if **all** of the following conditions are met:

- the well is drilled where step-out does not exceed one legal subdivision, **and**
- the pool already consists of a minimum of four wells, **and**
- all initial survey requirements have been fulfilled (test conducted within 1 legal subdivision of a step-out well), **and**
- there is no other pool in the same formation, in an adjacent quarter section, **and**

- the licensee/operator can provide evidence, upon request, indicating the well is completed in the existing pool.

Any further development in the quarter section, outside of the one LSD buffer zone, requires an initial pressure survey (one well per pool per quarter section).

Initial pressures are not required on wells in which production is occurring from a development entity in accordance with Section 3.051(1) of the *Oil and Gas Conservation Regulations*.

Initial pressures for wells in which production is occurring under self-declared commingling in accordance with Section 3.051(2) of the *Oil and Gas Conservation Regulations* shall conform to the requirements laid out in Section 4.6.10 of this directive.

Initial pressures are not required for wells with production commingled under Southeastern Alberta Order No. MU 7490 or any successor orders, with the exception of CBM and shale gas control wells, which must be tested as required by Section 7.025 of the *Oil and Gas Conservation Regulations* and, for gas production from coals, *Directive 062: Coalbed Methane Control Well Requirements and Related Matters*.

The testing requirements for CBM and shale gas control wells are described in Section 7.1.

Other testing methods that may be acceptable are addressed in Section 5.

3.3 Deliverability Testing Requirements

(See Sections 4.3, 4.6.10, and 7.1 of this directive for additional information.)

Bottomhole deliverability relationships are required for all producing gas wells prior to or during the first three consecutive calendar months of sales.

Bottomhole deliverability relationships are not required on wells in which production is occurring from a development entity in accordance with Sections 3.051(1) of the *Oil and Gas Conservation Regulations*.

Bottomhole deliverability relationships for wells in which production is occurring under self-declared commingling in accordance with Section 3.051(2) of the *Oil and Gas Conservation Regulations* shall conform to the requirements laid out in Section 4.6.10 of this directive.

Bottomhole deliverability relationships are not required for wells with production commingled under Southeastern Alberta Order No. MU 7490 or any successor orders, with the exception of CBM and shale gas control wells, which must be tested as required by Section 7.025 of the *Oil and Gas Conservation Regulations* and, for gas production from coals, *Directive 062: Coalbed Methane Control Well Requirements and Related Matters*.

The testing requirements for CBM and shale gas control wells are described in Section 7.1.

3.3.1 Flaring in Conjunction with Testing

(See Section 4.4 of this directive for additional information.)

Any flaring or venting in conjunction with well testing must be conducted in accordance with *Directive 060: Upstream Petroleum Industry Flaring, Incinerating, and Venting*.

3.4 Drill Stem Tests (DSTs)

(See Section 4.7 of this directive for further information.)

There are no regulations requiring the conducting of DSTs, only for submission of DST information.

All DSTs conducted, including misruns, must be submitted to the ERCB in DST.PAS electronic format, within 30 days of the well's finished drilling date.

3.5 Fluid Analyses

(See Section 4.8 of this directive for further information.)

All fluid analyses conducted on samples gathered at a well which are representative of the formation (not mixed stream), must be submitted.

Further, gas and/or fluid analyses are required in conjunction with the following tests:

- DSTs conducted on wells outside of existing pools, as per the current ERCB pool order
  - fluid analysis is required if fluid is recovered during the test
  - gas analysis is required if gas to surface during the test
- All deliverability tests require gas analysis for the fluid analysis correlation and must therefore be submitted with an AOF test on all wells drilled outside of existing pools, as per the current ERCB pool order.
- Initial Pressure Tests conducted on wells outside of existing pools, as per the current ERCB pool order:
  - gas analysis is required for oil and gas wells,
  - fluid analysis is required for oil wells, and gas wells producing liquids, OR
  - provide details regarding the source of analysis used in the correlation.
- Acoustic Well Sounder Tests require analysis information when calculating acoustic pressures:
  - gas analysis is required for all acoustic tests,
  - fluid analysis is required when fluids are present in the wellbore, OR
  - provide details regarding the source of analysis used in the correlation.
- Pressure Transient Analysis requires gas and fluid properties for calculations, or provide details regarding the source of analysis used in the correlation.

Wells in which production is occurring under the development entity or self-declared commingling process in accordance with Section 3.051 of the *Oil and Gas Conservation Regulations* are exempt from the fluid analyses requirements noted for the above tests. Rather, initial produced fluid analyses are required from the total production stream for each fluid produced from each well producing in accordance with Section 3.051, and must be conducted within 30 days of the well being commingled.

Additionally, wells producing under the self-declared process in which the well's average operating day flow rate for the first 3 calendar months with production immediately following the well being commingled under the self declared process is greater than 50 10^3 m^3/operating day require individual pool fluid analyses on all produced fluids for each main individual contributing pool. These analyses must be conducted within 30 days of the well being

commingled in accordance with Section 3.051(2) of the *Oil and Gas Conservation Regulations*. See Section 4.8 for further detail on this requirement.

3.6 Annual Pressure Survey Requirements

(See Sections 4.5, 4.6.10, and 7.1 of this directive for additional information.)

Annual pressure surveys must be conducted by year end (December 31) for oil and gas pools, as specified in the annual survey schedules:

- Survey 25 per cent of the producing well count in oil pools, based on quarter section spacing (e.g., approximately one survey per pool per productive section).
- Survey 25 per cent of the producing well count in gas pools, based on one section spacing.

Annual pressure surveys are not required on wells in which production is occurring from a development entity in accordance with Section 3.051(1) of the *Oil and Gas Conservation Regulations*.

Annual pressure surveys for wells in which production is occurring under self-declared commingling in accordance with Section 3.051(2) of the *Oil and Gas Conservation Regulations* shall conform to the requirements laid out in Section 4.6.10 of this directive.

Annual pressure surveys are not required for wells with production commingled under Southeastern Alberta Order No. MU 7490 or any successor orders, with the exception of CBM and shale gas control wells, which must be tested as required by Section 7.025 of the *Oil and Gas Conservation Regulations* and, for gas production from coals, *Directive 062: Coalbed Methane Control Well Requirements and Related Matters.*

The testing requirements for CBM and shale gas control wells are described in Section 7.1.

Section 4.6.8 includes details regarding survey requirements for pools with reduced spacing.

3.6.1 Licensee/Operator Requirements

(See Section 4.5.5 of this directive for additional information.)

Where more than one licensee/operator produces from the same pool:

- A Coordinating Operator will be designated by the ERCB and deemed responsible for coordinating the surveys for the pool(s).
- All licensees/operators in the pool(s) are required to cooperate with the Coordinating Operator.

See Section 6 on compliance and enforcement.

3.7 Submission Requirements

(See Section 4.9 of this directive for further information.)

The results of all well tests conducted must be submitted to the ERCB, in electronic format, as per Section 11.120 of the *Oil and Gas Conservation Regulations*, and in Appendix A: WTC PAS File Submission Formats, Business Rules, and Implications for Noncompliance.

All pressure and deliverability tests must be submitted within 90 days of completing the fieldwork, including reporting of volumes and methods produced during cleanup and testing.

All DSTs must be submitted within 30 days of the well's finished drilling date, including misruns.

All gas and fluid analysis must be submitted within 45 days of the completion of the test.

All volumes produced, whether flared, vented or collected (in-line) must also be reported through the Petroleum Registry of Alberta.

Notwithstanding the above, a test that failed and provides no useful data, especially where the use of this information might be misleading, does not have to be submitted. This does not include Drill Stem Tests, as detailed above.

Although there are no standard well testing requirements for bitumen wells in designated oil sands areas, all tests conducted must still be submitted to the ERCB. All of the gas well testing requirements and provisions of this directive apply to gas wells in the designated oil sands areas.

4 Clarification of the Minimum Requirements

Sections 4 through 7 of this directive provide additional interpretation of the basic testing requirements, guidelines for meeting and/or modifying the basic requirements, and examples of situations where the ERCB may require special testing which exceed these minimums. Together they represent the minimum requirements for well testing which are considered essential for prudent reservoir management. Recommended practices are also included under many of the sections, to assist well testers in meeting their requirements and obtaining the best data possible.

4.1 Basic Requirements

The basic requirements apply to pools and wells as described in this directive, until or unless the licensee/operator and the ERCB agree relief is appropriate. The requirements focus on data gathering from discovery until a pool is fully developed. Gathering quality data during this phase is critical. The basic requirements, with modifications for relief when appropriate, should address the testing needs of the majority of Alberta's reservoirs.

Noncompliance with these well testing requirements will result in enforcement action in accordance with *Directive 019*.

4.2 Initial Pressure Testing

Requirement: Initial subsurface pressure tests are required to be collected on new productive oil and gas wells, and reported in electronic format (PAS), as follows:

- **Gas Wells – on all new wells drilled, within the first three months of production (one well per pool per section),**
- **Oil Wells – on all exploratory, discovery, development or step-out wells; prior to any sales or production, other than test production (one well per pool per quarter section)**

Wells in which production is occurring from a development entity or under self-declared commingling in accordance with Section 3.051 of the *Oil and Gas Conservation Regulations* shall be tested as set out in Section 4.6.10.

An accurate initial pressure is probably the most important pressure taken in a well. It determines the initial pool pressure in exploratory wells, it helps delineate pools in development wells, and it can show the drainage and recovery efficiency in infill wells. Without this pressure, subsequent pressures may be of limited value.

The ERCB has added a list of those wells with outstanding initial requirements on the ERCB Web site www.ercb.ca under Industry Zone : Rules, Regulations, Requirements : Well Testing - Pressure Survey Schedules. This list is updated biweekly, and displays the unique well identifier, the licensee, and the type of test required.

4.2.1 Relaxation of Initial Pressure Requirements on Step-out Oil Wells

Initial pressures are not required on step-out wells to existing oil pools if **all** of the following conditions are met:

- the well is drilled where step-out does not exceed one legal subdivision, **and**
- the pool already consists of a minimum of four wells, **and**
- all survey requirements have been fulfilled, **and**
- there is not another pool in the same formation, in an adjacent quarter section, **and**
- the licensee/operator can provide evidence upon request, indicating the well is completed in the existing pool.

Important Note: If you do not survey a step-out well, any further development drilling in that quarter section requires testing, even if that quarter section gets added to the ERCB pool order, (one initial survey must be conducted per quarter section).

The initial survey requirement can be waived for wells drilled outside of an existing pool boundary (using the ERCB's current pool order ***at time of drilling***, as per Figure 1 on the following page), where the step-out is within the one legal subdivision (LSD) buffer zone and there is a high probability of extending the existing pool. The conditions listed above permit the waiver of the initial pressure survey requirement, while ensuring that only pools with an established pressure history and areal extent receive waiver. Also, they ensure that wells between two same formation pools have adequate initial pressure data to allow determination of pools.

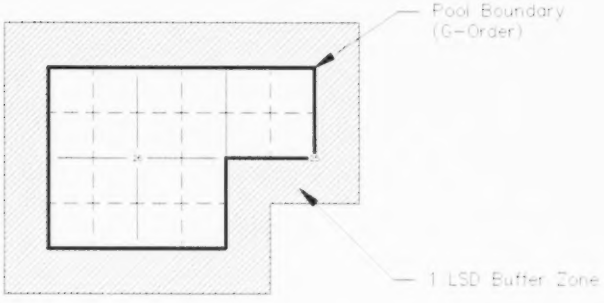

Figure 1. Pool Order with Buffer Zone

The ERCB does not currently have an automated process to administer the waiver for these step-out wells. Therefore, it is necessary for the licensee to respond to the notice letter, and advise ERCB staff that the well qualifies for exemption due to the step-out rule. ERCB staff will then review the situation and determine the requirement accordingly.

Similar problems are often experienced with wells drilled within an ERCB Pool Order that do not initially get coded into the pool, or into the Southeastern Alberta Shallow Gas System. In these cases, the licensee is also required to respond to any notice letters, and advise ERCB staff of the criteria for exemption.

4.2.2 Initial Pressures on Gas Wells

Initial pressures have always been required on all new productive gas wells and are considered to be very important to the management of oil and gas resources. Since June 1, 1999 the initial pressure requirement for gas wells has been administered in the same manner as oil wells, with the same compliance processes applying.

The changes to the management of commingled production in the wellbore introduced in 2006 resulted in wells producing from a development entity or under self-declared commingling in accordance with Section 3.051 of the *Oil and Gas Conservation Regulations* having modified initial pressure testing requirements as set out in Section 4.6.10.

Also in 2006, testing requirements for CBM and shale gas control wells were implemented as described in Section 7.1.

4.2.3 Recommended Practices for Initial Pressure Tests

The initial stabilized pressure should be taken before any significant production or depletion of the reservoir occurs. Taking the initial pressure after a reasonable cleanup flow period is acceptable providing the test shows that a stabilized reservoir pressure has been reached. But it would be unacceptable, for example, to wait until the end of the 4-month New Oil Well Production Period to take an oil wells' initial pressure, or to apply for relief from testing.

When using a static gradient for an initial pressure test, the licensee/operator needs to be aware that the formation has been disturbed and some drawdown has occurred during drilling, completion, and clean up. A static gradient without sufficient shut-in may not indicate a stabilized pressure. In many instances, running a static gradient and leaving the gauges on bottom for a few hours gives a good indication of stability for an initial pressure.

Although the taking of an initial pressure is not required for infill oil wells, it is recommended whenever practical to do so. It should also be noted that initial pressures can be used to meet the annual pool pressure survey requirement providing areal coverage is satisfactory.

Under certain conditions, an acceptable initial pressure can be obtained from alternative methods as addressed in Section 5 of this directive.

4.3 Gas Well Deliverability Testing

Requirement: Obtain a sandface deliverability relationship for ALL producing gas wells from either a single or multi-point test, prior to the end of the first three calendar months of production, and report in AOF.PAS format. Wells in which production is occurring from a development entity or under self-declared commingling in accordance with Section 3.051 of the *Oil and Gas Conservation Regulations* shall be tested as set out in Section 4.6.10

A deliverability test is a test to predict the absolute open flow potential (AOFP) of a well, and its deliverability potential under various pipeline backpressures. A deliverability relationship is needed because a gas well may not be producing at capacity. A gas well's deliverability is a function of wellbore configuration and gathering system back pressure, and requires a stabilized flow rate.

A stabilized rate is required to be a calculated value, based on the time to pseudo steady state. This calculation corrects the actual extended test rate to a lower estimated stabilized rate. Higher permeability reservoirs will have very little correction to stabilize, where lower permeability reservoirs will have a large correction. Although the time to pseudo steady state varies with the well geometry and reservoir shape, one can assume a well in the center of a one-section drainage area for a gas well; or if the data or mapping suggests a different drainage area, adjustments must be made as indicated in Section 5 of ERCB *Directive 034: Gas Well Testing Theory and Practice.*

This directive recognizes concerns regarding the flaring or venting of gas during an initial test, and the validity and cost of repeated deliverability tests. Therefore, the above requirement strives to obtain the most practical test design and early production forecasting. The type of deliverability test, single or multi-point, is left up to the licensee/operator. More information is available in Section 4.3.1 below.

The licensee uses this information to assess tubing string design, determine the economics of tying in a well, to size surface processing facilities, and pipeline gathering systems. The ERCB uses this information in reserves determination, provincial forecasts of gas deliverability, and in processing applications for gas plants, pipelines, batteries, etc. In addition, this data is made available to the public for multiple purposes, including drilling release rate calculations and property evaluation.

Further deliverability testing is not required, providing a reliable long-term relationship is determined by the above methods, and the ERCB has not defined special needs. Some suggestions for test design are included in the following sections.

There is no deliverability test requirement for oil wells but where such tests are run they must be filed with the ERCB, as per Section 11.005 and 11.120 of the *Oil and Gas Conservation Regulations*.

4.3.1 Recommended Practices for Gas Well Deliverability Tests

In-Line Testing should always be the Preferred Option After Appropriate Clean-up

To determine the type of deliverability test to conduct, consider.

- Public/environmental impact of the test atmosphere.
- The primary objectives of the test.
- The magnitude of data needed (e.g., multi-point versus single-point, surface versus bottomhole).
- The type of reservoir (permeability, drive mechanism).
- Test rates and flow periods must be designed to minimize flaring (see Section 4.4 for more information on flaring and emissions).
- The initial test should be a multi-rate test when the anticipated AOFP of the well is 300 10^3 m^3/d (10.6 MMscfd) or greater, or if turbulence is a factor.

- Tests which involve flaring are not intended to provide reservoir limits information, only to prove sufficient reserves to warrant expenditures for tie-in and facilities.

4.3.2 Types of Deliverability Tests

The main types of deliverability tests used today are:

Flow After Flow Test: requires a static reservoir pressure and stabilization of three to four flow rates. This test provides good radius of investigation, but often results in a lengthy test, resulting in excessive flaring of gas. For this reason, this test is best for use in high permeability reservoirs that stabilize quickly otherwise serious consideration should be given to testing in-line.

Isochronal Test: requires a static reservoir pressure, a flow period of fixed duration, followed by shut-in until pressure stabilizes again. This sequence of flow and build-up to stabilized pressure is repeated with only the final or extended flow rate required to stabilize. This test is still quite lengthy, and again best suited to high permeability reservoirs.

Modified Isochronal Test: requires a static reservoir pressure, then flow and shut-in periods of equal duration. This method was developed for testing tight reservoirs, but is often used today on high volume, tubing restricted and/or partially penetrated wells with fair to good permeability.

Single Point Test: requires a stabilized rate and flowing pressure measured before the well is shut in and built up to a stabilized reservoir pressure. This test is widely used for deliverability tests where the turbulence factor is known; usually for subsequent tests on a well, for initial tests in a relatively mature pool, or where deliverability may be poor or flow conditions are predetermined by pipeline or plant restrictions.

A build-up test conducted with any type of deliverability test, will provide information on current reservoir pressure, permeability, formation flow capacity, apparent skin and reserves should depletion be detected. A multi-rate deliverability test will indicate the effect of pressure loss due to turbulence.

Other considerations when designing a deliverability test:

- environmental and safety requirements (see *Directive 060*),
- expected H_2S percentage/maximum release rates,
- flare dispersion modeling (flare stack design and cumulative assessment as per Section 4.4.3 of this directive),
- flare efficiency (if flaring),
- down wind monitoring needs,
- surroundings, inhabitants, cottage country,
- time to stabilization (permeability),
- flow rates, restrictions and duration of flow (higher rates do not necessarily increase the radius of investigation – see *Directive 034* for further information),
- backpressure,
- turbulence effects,
- well depth,

- wellbore configuration (hydrate range, liquid loading, clean-up needs, etc.),
- type of stimulation,
- fluid analysis needs,
- coning/drawdown limitations,
- test equipment sizing,
- wellbore storage (downhole shut-in tool),
- interference effects/other producers in the area, and
- gauge pressure rating should be matched to expected flowing and reservoir pressure
  - a high pressure gauge in a low pressure reservoir may cause stairstepping and introduce noise affecting derivatives used in test interpretation
  - a low pressure gauge in a high pressure reservoir will compromise the mechanical integrity of the gauge.

It is recommended that a second deliverability check be conducted after a well stimulation treatment, as follows:

- obtain a flowing bottomhole pressure using a properly calibrated subsurface gauge, in most cases, during a period of stabilized flow,
- the flowing pressure should be taken just prior to shutting the well in for its second pressure survey, and
- if the stabilized flow is interrupted in order to run subsurface gauges, production should be resumed at the previous stabilized rate for about 10 times the interruption, to obtain the flowing pressure.

Whenever possible, product content tests, a second deliverability check, and a second pressure survey should be scheduled together.

The general practices in ERCB *Directive 034* should be followed.

4.3.3 Surface Testing Dry Gas Wells

In order to estimate a stabilized pressure or the productivity/absolute open flow potential of a gas well, it is necessary to determine the bottomhole pressures at static and flowing conditions, either by actual measurement with a bottomhole pressure gauge, or by calculation from wellhead pressure measurements. Because it is often not cost effective to measure static and flowing pressures by downhole gauge in lower productivity gas wells, estimations may be made from wellhead data gathered by accurately calibrated deadweight gauge.

The calculation of a bottomhole pressure from data measured at the wellhead involves the solution of the energy balance equation as applied to both static and moving columns of gas. There are several methods available for this solution and reference should be made to *Directive 034*. This pressure must be reported in the GRD.PAS format to meet the initial pressure requirement.

The calculation for a single-phase fluid (gas) in the wellbore requires knowledge of the wellhead pressures, the properties of the natural gas, the depth of the well, flow rates, formation and wellhead temperatures, and the size of the flow lines. Appendix B of *Directive 034* introduces the theory and basic equations relating these quantities. Methods utilizing the

basic equations and simplifying assumptions to make them practical are outlined. The recommended procedure is discussed in detail and is illustrated by appropriate examples.

Also included in *Directive 034* is a simple method for the estimation of bottomhole pressures for gas-condensate wells.

4.3.4 Relaxation of Sandface AOF Requirement

The need for deliverability data diminishes as the potential of a gas well drops. Where a stabilized wellhead absolute open flow potential (WAOFP) is 20 10^3 m^3/d (~710 Mscfd) or less, and where liquid loading does not mask the well's downhole potential, the wellhead and the sandface deliverability potentials are close enough to be considered the same. In such cases, a single point wellhead deliverability relationship is acceptable, using an inverse slope of "n" = 1.0.

There may be instances beyond the 20 10^3 m^3/d rate where a sandface AOF is not necessary. This could occur in a well established area, where there is sufficient deliverability data to correlate from sandface AOFs to surface data. In these instances, licensees are encouraged to make application to increase the 20 10^3 m^3/d limit. Such applications should be made on a pool/area/field basis, on higher rate, low-pressure wells, where production is unrestricted. Applications must include a correlation between actual measured sandface and surface data, and must address issues like tubulars, restrictions, etc. A fluid shot should always be used to indicate the absence of liquid in the wellbore.

4.3.5 Exemption from Initial Deliverability Requirements

Exemption from initial deliverability requirements, similar to the Southeastern Alberta Shallow Gas system, will continue to be administered on an application basis. Such application may be made for well-established areas, with substantial historical data available. The ERCB will continue to gather information from these applications to enable future definition of criteria and areas for exemption or relaxation of requirements.

These applications may be made on a well or a pool basis and should include:

- correlation of historical pressure and deliverability data, establishing predictable trends,
- consistencies across the field/area, and
- production trends.

4.3.6 Reporting Deliverability Tests

Requirement: All deliverability tests conducted must be submitted in the TRG.PAS electronic format, as defined in Appendix A. A PRD.PAS file must be submitted for all tests involving flaring, incineration or venting and any other test where production testers have been used.

The initial deliverability requirement will not be considered fulfilled until/unless absolute open flow and production rate data files have been submitted and accepted by the ERCB, as indicated above (in-line production information is to be provided in the DTINRPR - Data Table – Inline Rate and Pressure Summary - portion of the TRG.PAS file). The most current version of all PAS formats is available from the links in Appendix A.

Failure to comply with this requirement will result in enforcement action in accordance with *Directive 019*.

Requirement: You must submit volumetric data for a well that has produced any fluid (crude oil, crude bitumen, condensate, gas, or water) as outlined in *Directive 007: Volumetric and Infrastructure Requirements.*

These volumes and the method of production (flared, incinerated, vented, or in-line) must also be reported in the AOF.PAS electronic report.

4.4 Flaring and Emissions During Well Testing

Flaring Must Always Be Kept to a Minimum

Requirement: All flaring, incinerating or venting during well testing must be conducted in accordance with *Directive 060*.

Since the gas is the sole commodity or revenue generator when testing a gas well, the natural economic incentive to not flare more than necessary should keep the volumes as low as possible. Licensees must ensure that tests are designed to minimize flaring, incinerating, venting and lost production. Where gathering and processing infrastructure are in close proximity, the ERCB expects operators to recover well test gas as an alternative to flaring.

Tests involving flaring, incinerating or venting are not intended to be reservoir limits tests, but only to prove sufficient reserves to warrant expenditures for tie-in and facilities.

Well testers must continually look at new technologies to reduce the amount of flaring, incinerating and venting for environmental and conservation reasons. The ERCB encourages licensees to test in-line wherever possible. If this results in a delay in submitting the initial deliverability test, approval for an extension can be obtained via e-mail to the Well Test Helpline at *welltest-helpline@ercb.ca.*

4.5 Annual Pool Pressure Surveys

Requirement: Annual surveys are required on oil and gas pools, as specified in the annual survey schedules as follows:

- **Survey 25 per cent of the producing wells based on quarter section spacing in oil pools (e.g., One survey per producing section), and**
- **Survey 25 per cent of the producing wells based on one section spacing in gas pools.**
- **Wells in which production is occurring from a development entity or under self-declared commingling in accordance with Section 3.051 of the *Oil and Gas Conservation Regulations* shall be tested as set out in Section 4.6.10.**

Tests intended to fulfill survey requirements must meet the standards set for "acceptable tests" as defined in Section 5 of this directive.

It is the responsibility of the Coordinating Operator to ensure these requirements are met, or to address any inaccuracies with ERCB Well Test staff (e.g., change of licensee responsibility due to sale of property, or a change in productivity or recoverable reserves). Full details on licensee/operator responsibilities are found in Section 4.5.5 of this directive.

4.5.1 Developing the Survey Schedules

Pressure data is considered most important in the initial and developing years of oil or gas pools, to assist in determining pool delineation, reserves, recovery mechanism, waterdrive or influx activity, and optimum depletion strategy.

The parameters considered by ERCB staff when adding new oil or gas pools to the survey schedules are:

- ERCB's recoverable reserves (see ERCB publication *ST98: Alberta's Energy Reserves and Supply/Demand Outlook*,
- number of productive wells,
- existing pressure data,
- productivity,
- fluid density,
- unique reservoir characteristics,
- specifics to the area, and
- the need for the data.

These parameters are reconsidered each year. Therefore, a pool may be added to the survey schedule if productivity has increased, if new development has occurred in an existing pool; or it may be deleted if the pool now qualifies for advanced depletion. In addition, special needs are identified and pools are added through the application process, to monitor equity issues, enhanced recovery feasibility, progress of enhanced recovery schemes, concurrent production, good production practice, special allowables, etc. These special needs will be a condition of the approval or the letter of disposition.

Only those pools that meet the following criterion are added to the survey schedule, unless a special need has been identified:

	Oil Pools	Gas Pools
Recoverable Reserves	=> 15 10^3 m^3 (94 347 bbl)	=> 30 10^6 m^3 (1.06 bcf)
Well Productivity (operating day rate)	=> 5 m^3/operating day	=> 5 10^3 m^3/operating day
Stage of Depletion	< 50%	< 50%
Oil Density	<= 925	

Pools that do not meet the above criterion and where no special need has been identified, will not appear on the survey schedule, and do not require testing. However, any tests conducted on any well/pool must be submitted to the ERCB. Any new wells drilled into these pools, will be subject to initial testing requirements as per Sections 4.2 and 4.3.

Once the survey schedule has been published for the year, no pool will be added to the survey schedule for that year without written notification to the coordinating operator or pertinent well licensee. The next update of the schedule on the ERCB Web site will include that pool.

Due to the need to define the pools requiring surveys very early in the year, it is necessary to assess the productivity based on the previous year's production. If a well/pool has declined to below the minimum productivity rates indicated above, it may be appropriate to review the survey requirement and apply for relaxation. However, to qualify for this reduction, all wells

in the pool must have limited production, as exemption will not be given for individual wells or portions of pools.

Due to the timing of the survey schedule, a well could appear on the survey schedule that has since suspended production, or declined to below the criterion listed above. As long as the pool is on the survey schedule, the coordinating operator is responsible for testing, or requesting that the pool be removed from the survey schedule. This can be done by contacting the ERCB Well Test Section as per Appendix B.

4.5.2 Special Circumstances

Some oil and gas pools and wells have special circumstances defined and will be identified with a survey frequency of "SPECIAL CIRC" on the survey schedule. These circumstances are usually defined through the approval process and the letter of disposition, but the particulars will be identified in Appendix I to the survey schedule.

Situations which may result in special circumstances being assessed are:

- oil pools
  - approval clauses for enhanced recovery, good production practice, concurrent production, etc.
  - partial pool requirement
  - special areal coverage requirement
  - specific wells that require monitoring
  - observation wells
- gas pools
  - off target wells
  - acid gas disposal wells
  - gas cycling schemes
  - gas storage wells
  - observation wells

4.5.3 Publication of Survey Schedules

The survey schedules are published early each year, usually the end of January or early February, and Industry is notified of availability by e-mail from the Welltest-Helpline and posted letters. The survey schedules are posted on the ERCB Web site, complete with current status (e.g., fulfilled, outstanding, partially fulfilled, not required, etc.). This file will be updated monthly. For further information on accessing this file, see Section 4.5.4 below.

It is the Coordinating Operator's responsibility to determine the pools for which he is responsible, and contact the other operators in the pool to coordinate the survey. There is a sample letter included in this directive that can be used for this purpose (see Attachment I). See Section 4.5.5 for more information on the responsibilities of the Coordinating Operator.

4.5.4 Extracting Annual Survey Schedule Information from the Internet

The survey schedules for oil and gas pools are available on the ERCB's Web site www.ercb.ca under Industry Zone : Rules, Regulations, Requirements : Well Testing - Pressure Survey Schedules.

4.5.5 Licensee/Operator's Responsibilities

Requirement: Where more than one licensee/operator produces from the same pool:

- **A Coordinating Operator will be designated and deemed responsible for coordinating the surveys for the pool, and ensuring the pool's survey requirements are fulfilled as required by this directive.**
- **All licensee/operator(s) in a pool are required to cooperate with the Coordinating Operator in planning, conducting, and submission of pressure survey data sufficient in quantity and quality to fulfill the pool's survey requirements as required by this directive.**

All parties that obtain revenue from a pool are expected to share the burden of testing. A cooperative approach to pressure testing should result in the best well selection and the lowest costs, therefore, every effort should be made to develop a single coordinated program.

A Coordinating Operator will be designated for each pool on the survey schedule. The ERCB program selects the Coordinating Operator automatically as the operator who produced the largest total volume of oil or gas from the pool in the previous year. The Coordinating Operator is the ERCB's primary contact for testing in a pool, as well as being deemed responsible for ensuring the pool's survey requirements are fulfilled.

The main duty of the Coordinating Operator is to develop and coordinate pool pressure survey programs with the input and assistance of the other licensees/operators in the pool. The Coordinating Operator should always be cognizant of opportunities that permit timely pool pressure surveys to be conducted during scheduled shut downs and plant turn-arounds.

An example of the procedure for developing a pressure survey program for a pool is given in Section 4.6.11.

If a Coordinating Operator has fulfilled their part of the requirements, but their efforts to coordinate the survey with the other licensees/operators have been to no avail, they may provide the ERCB with documentation of communications (e.g., copies of letters, e-mails, documentation of telephone calls, etc.). The responsibility will then shift to the uncooperative licensee/operator(s). Again, the survey schedule and the current status for each pool is on the ERCB Web site to assist the licensees/operators in ensuring the survey requirements are fulfilled, as referenced in Section 4.5.4.

4.5.6 Licensees' Responsibilities when Buying/Selling Wells

It is the responsibility of the licensees, both the seller and the buyer, to ensure a proper well license transfer is filed with and approved by the ERCB's Liability Management Group. If the seller of the property is the Coordinating Operator, it is their responsibility to advise the ERCB Well Test Section of the change of responsibility to avoid assessment of noncompliance fees. The ERCB considers the original licensee responsible until this process is complete (see *Directive 006: Licensee Liability Rating (LLR) Program and Licence Transfer Process* for more information).

If the previous licensee was deemed responsible during the first 3 months of consecutive production, they are expected to contact the ERCB Well Test staff within the timeframe specified on the ERCB Outstanding Initial Pressure and Deliverability Testing Requirements list. Failure to do so, will result in the assessment and liability of a $1000.00 noncompliance fee.

4.5.7 Determining the Number of Surveys Required

Having regard for testing costs and adequate pressure coverage, the minimum number of pressure surveys should equal about 25 per cent of a pool's producing well count, based on quarter section spacing for oil pools. This translates to one survey per productive section. For gas pools, one survey per four productive sections is required. This does not necessarily mean that only productive wells should be surveyed, or that a well must be surveyed in every productive section for oil wells (e.g., if there is only one productive well in a section, an offset well is acceptable).

Many oil and gas pools are single well pools. For these pools, the 25 per cent rule may be interpreted as one pressure survey every fourth year, once the initial survey requirements have been fulfilled. Similar interpretations can be applied to two well pools for "biennial" survey frequency.

It is important to remember that the initial pressure requirement would still apply to any new wells drilled into these pools. Three and four well pools on the survey schedule would require annual surveys as a minimum, based on normal spacing (quarter section for oil pools and one section for gas pools, assuming no special needs have been identified).

The testing requirements for commingled wells described in Section 4.6.10 and for CBM and shale gas control wells described in Section 7.1 also must be considered.

4.5.8 Selecting Wells to be Surveyed

It is usually considered impractical to shut in an entire pool to conduct a pressure survey. However, if interference is a problem, it may be advisable to shut in offset wells for the duration of the test.

Costs are significantly reduced if some pressures from new or shut-in wells are used to meet the requirements, provided they are representative of the producing portion of the reservoir. For example: if the well is shut in because it was in poor communication with the reservoir, it will not provide a representative pressure measurement for this pool. The practice of utilizing opportunities to survey at reduced costs is encouraged, where adequate areal coverage is not sacrificed and some producing wells are included in the survey.

4.5.9 Observation Wells

Shut-in wells can be candidates for testing and reduce the cost of a required pressure survey, **provided** they are representative of the producing portion of the pool, as described above. It is unacceptable to use a well that was shut in because of poor communication with the pool. An annual survey utilizing shut-in well(s) should include a combination of producing wells, and provide adequate areal coverage of the pool. A good example of utilizing a shut-in well for observation purposes is to monitor the pressure of an aquifer where water disposal could result in over-pressuring.

Plans to retain a shut-in well as an observation well requires that changes be made to the well status in the Petroleum Registry. All requests for "observation well" status are forwarded to the Well Test Section for approval. Applicants will be required to provide information regarding the type and need of the data being gathered. This information will be considered in conjunction with requirements for that well/pool, data reported to the ERCB, and long term implications regarding the ERCB's requirements for the administration of inactive wells.

Once an observation well is approved, the ERCB will conduct random audits to monitor the ongoing use of the well for observation purposes. If the intent of the observation well was to monitor pressure data, the pool will be added to the annual survey schedule, with full compliance administration. The pool will remain on the survey schedule until the licensee requests exemption and the well reverts back to the inactive well administration system.

4.5.10 Pools on Good Production Practice

Do not assume that pools on Good Production Practice (GPP) are exempt from pressure survey requirements. That assumption may have been fairly safe in the past, when GPP was only granted after years of production and pressure data very clearly indicated a well established trend. Today, GPP may be granted early in the life of many pools, and ongoing pressure data is critical to monitor the effects of higher withdrawal rates during development of the pool.

4.6 Modifying the Basic Requirements

Pressure survey requirements are set early in the life of a new pool, when the well(s) are most productive. The ERCB program routinely waives ongoing testing requirements, without application, for pools that meet the criteria for exemption defined in Section 4.5 of this directive, unless special needs have been defined. For example, pools with enhanced recovery, off-target wells, special pressure clauses in GPP and CCP approvals will remain on the survey schedule until such time as the ERCB and the licensee(s) agrees that pressure data is no longer required.

However, once a pool is fully developed and the questions of pool delineation, reserves, recovery mechanism, etc. have been answered, survey requirements may be reduced. When a licensee believes that a pool should qualify for relaxation or exemption, a request for relief should be made to the ERCB, including supporting data to substantiate the change.

Important Note: Licensees/Operators should be aware that reduction of survey requirements will NOT be considered for any pool unless all survey requirements have been fulfilled to date.

Other examples where a pool may qualify for waiver of survey requirements for a specific year would be if an extensive test was conducted in the previous year, if withdrawals have been negligible since the last survey, if the entire pool must be shut in to obtain quality data, etc.

Described below are situations where the licensee/operators should consider requesting either relaxation or exemption from the basic requirements. This provides more flexibility for the licensee/operator to conduct the tests needed for their own use, but not at scheduled intervals tracked by the ERCB. While each situation must be considered on its own merits, some general guidelines are provided to streamline the process, and to show how requests for relief may be approved. All requests should be directed to the ERCB's Well Test Section of the Information Collection and Dissemination Group at the ERCB Calgary Office.

THE NEED FOR THE DATA SHOULD ALWAYS BE THE MAIN REASON FOR TESTING.

Please note that applications for waiver or exemption of the survey requirements received after November 1 of the current year may result in two surveys being required in the following year, if the application is denied.

Also described below are the requirements for testing wells that are commingling production from two or more pools in the wellbore, where such requirements vary from the standard requirements stated elsewhere in this directive.

4.6.1 Declining Productivity

Due to the need to define the pools requiring surveys very early in the year, it is necessary to determine productivity based on the previous year's production. If a well/pool has declined to below the minimum productivity rates indicated in Section 4.5.1, please contact ERCB Well Test staff as indicated above. To qualify for this reduction, all wells in the pool must have limited production. Exemption will not be granted for individual wells or portions of pools.

4.6.2 Heavy Oil Pools

The pressure response of a reservoir fluid is a function of the fluid's viscosity. The heavier the density of the crude oil at reservoir conditions, the more viscous the fluid. Oil densities over 900 kg/m^3 are considered heavy enough to merit consideration for relief from the annual pressure survey testing requirements. Pools with an oil density over 925 kg/m^3 will only be added to the annual survey schedule if special circumstances exist (e.g., waterflood). Between 900 and 925 kg/m^3, the licensee/operator is expected to provide supporting evidence in a request for relief from pressure testing. This evidence should include field data and analyses, which show that stabilized reservoir pressures cannot be obtained using conventional survey methods.

Relief may range from reduced pool pressure survey requirements to complete exemption. In general, the initial pressure requirement would still apply, and is probably needed to make a case for relief. Relief will not be granted on the basis of an oil density below 900 kg/m^3.

There are no standard survey requirements for bitumen wells within designated oil sands areas, although any surveys conducted must be submitted to the ERCB.

4.6.3 Low Permeability Pools

The time required for pressure build-up is inversely proportionate to permeability. In general, whenever a reasonable estimate of the stabilized reservoir pressure can be obtained within a 14-day shut-in period (using build-up or static pressure measurements), the basic pressure requirements apply. A measured or extrapolated pressure that is at least 95 per cent of the fully built-up pressure is considered adequate for most reservoir management/ development applications.

Where it takes more than 28 days to estimate a stabilized pressure, exemption from pool pressure surveys may be granted upon application. Between 15 and 28 days, relaxation may be granted upon application, depending upon the need for the data. For example, where a 21-day shut-in period is needed to gather sufficient data for a transient pressure test, the number of pressure surveys may be halved. These applications require supporting evidence including interpretation of previous pressure buildup tests, establishing the reservoir parameters pertinent to the application. For further information on time to stabilization see ERCB *Directive 034*.

4.6.4 Small Reserve Pools

The economic burden of testing increases with smaller pools. Therefore, the pool pressure survey requirement will be routinely waived for oil pools with established recoverable reserves less than 15 10^3 m^3 (94 347 bbl), and for gas pools with recoverable reserves less

than 30 10^6 m^3 (1.06 bcf). The reserves, in this case, are the ERCB's established (recoverable) reserves as published annually. The initial pressure requirements remain in effect. However, where a licensee/operator can show, from a reliable production decline analysis, that a pool's recoverable reserves are small, as defined above, the pool pressure may be waived.

Most of these small reserve pools are single well pools. With the 25 per cent annual pool pressure survey rule, once a subsequent pressure has been submitted, further testing would not normally be required for another four years. By this time, the pool's recoverable reserves and boundaries should be defined with some confidence.

4.6.5 Reserves Review

When a licensee believes that a pool on the survey schedule should qualify for exemption under the recoverable reserves or stage of depletion criterion, a request can be made to the ERCB for such an exemption. If a change in the ERCB's reserves setting is required, an application for a change in reserves must first be made in accordance with *Directive 065: Resources Applications for Oil and Gas Reservoirs*. The ERCB will review the application and make a decision on whether a change in reserves is warranted.

4.6.6 Primary Pools with Advanced Depletion

When a pool has produced 50 per cent of its recoverable reserves, it will be exempted from the pool pressure survey requirement. The ERCB will endeavour to identify these pools, and not include them on the annual survey schedule, as addressed in Section 4.5, unless special circumstances have been identified. However, this does not preclude the licensee/operator's prerogative of requesting relief at any time. If a change in the ERCB's reserves setting is required, an application for such in accordance with *Directive 065*, as referenced above, is required.

4.6.7 Pools with Enhanced Recovery

Generally, survey requirements in a pool with enhanced recovery may exceed the minimum requirements, in order to monitor the effects of injection. In addition, survey coverage in patterned floods generally requires a representative pressure test on a producing well in each pattern. These special requirements, along with time lines for submission of test results, will be outlined in ERCB correspondence. Time lines may be specified for the submission of test results, to coincide with operational meetings with ERCB staff. Survey requirements/compliance should be addressed at these meetings.

Sufficient pressure data should be taken to determine the pressure for all recovery mechanisms, in pools where both primary depletion and enhanced recovery schemes are operating. When enhanced recovery has been deemed not feasible for the primary area, a relaxation or an exemption from testing in the primary area may be requested.

Pressure sinks or highs in pressure maintenance schemes should be monitored each year until the problem is corrected. Shut-in wells, within the producing area of a pool, may be good candidates for pressure observation, providing they are in good communication with the productive area of the pool. However, if a well is suspended because it is in a very tight portion of the reservoir, or an area that has watered out (the flood front has passed), it would likely not provide any useful data in determining the pressures and trends of the producing area. In general, pressures from shut-in wells and new wells (initial pressures), should be used together with pressures from producing wells to satisfy a pool's pressure survey requirement.

The use of injection wells as candidates for pressure testing usually results in a higher pressure and would not be acceptable for determining the pressure in the producing zone, or assessing whether producing wells are in compliance with a minimum operating pressure (MOP). In unique circumstances, where it has been shown by previously correlated data that a pressure from an injector is representative of the producing area of the pool, this may be deemed acceptable. This will usually occur when injection fluid is taken on vacuum (e.g., reef type pools).

When a horizontally flooded enhanced recovery scheme, with an MOP, is in its latter stages of depletion, the MOP may be reduced to the bubble point pressure, or some other applicable pressure. Requests to amend the operating pressure should be directed to the Reservoir Applications Group, and contain discussions on the suitability of the existing MOP and the proposed operating pressure along with future plans for the scheme.

Static gradient tests with short shut-ins (less than 14 days and below the stabilized conditions) but with pressures above the MOP or other approved operating pressure may satisfy survey requirements. However, prior approval must be obtained from the Well Test Section and Resources Applications Group.

Relaxation of pressure testing requirements in pools with enhanced recovery, occur mainly by application. Any requests for relief from pressure testing in pools with enhanced recovery must still be submitted to the Well Test Section, to ensure a temporary change in status for compliance purposes.

4.6.8 Pools with Reduced Spacing

Where a pool is developed on reduced spacing, application of the basic pool pressure survey requirement may be excessive because it is based on the pool's productive well count. In general, where reduced spacing is needed to improve recovery, more pressure coverage may be needed during the early stages of a new pool, or step-out development stages of older pools. However, survey requirements for these pools can usually be determined by using standard spacing, as referenced in Section 4.5 of this directive. If deliverability is the main reason for reduced spacing requirements, additional pressure coverage is generally not required.

4.6.9 Pools with Active Waterdrives

Once sufficient pressure data has been gathered to establish that a pool has an active waterdrive, the survey requirements can usually be reduced. While further development may change the ability of the waterdrive to maintain the pool pressure, surveying 25 per cent of the wells is not necessary. Approval for reduction of requirements in these situations should be requested.

4.6.10 Pools with Commingled Production

In pools where approval has been granted by an ERCB order to commingle production in a small number of wellbores in a pool, generally no change would be made to the survey requirements on the basis of the commingling.

In situations where most or all of the wells in two or more pools are approved for commingled production by an ERCB order, the usefulness of the commingled pressure data for individual pool analysis is diminished. In these cases, the pressure measured in the wellbore reflects an unknown combination of pressures from the different pools, often

complicated by the effects of crossflow. However, pressures taken on commingled pools in a wellbore can be useful for evaluating the potentially complex, multi-pool commingled system as a whole.

There are special cases where segregated individual pool pressure data is still required for commingled pools (e.g., enhanced recovery schemes), and specialized equipment may be required to obtain this information (e.g., sliding sleeves). For all other commingled pool cases, pressure and deliverability measurements on the composite "commingled pool" in the wellbore replace segregated individual pool test requirements.

The ERCB made significant changes to its management of commingled production in the wellbore in 2006. These changes acknowledged the shift to lower productivity resources, the prevalence of commingled production to achieve optimum resource recovery, and a shift in reservoir management and reserves evaluation and administration towards commingled reservoir situations. As part of these changes, well testing requirements for wells commingled under processes introduced in 2006 were modified. Specifically, wells that are producing from a development entity or under the self-declared commingling process in accordance with Section 3.051 of the *Oil and Gas Conservation Regulations* must be tested in accordance with the requirements specified below.

4.6.10.1 Gas Wells producing from a development entity

Wells producing from a development entity in accordance with Section 3.051(1) of the *Oil and Gas Conservation Regulations* do not require any initial or ongoing pressure or deliverability testing, except for coalbed methane and shale control wells as laid out in Section 11.145 of the *Oil and Gas Conservation Regulations* and discussed in Section 7 of this directive. However, if any such tests are conducted on wells producing from a development entity, the test data and analyses must be electronically submitted to the ERCB via the Well Test Capture system.

An analysis of each fluid produced from the commingled well must be performed and submitted electronically to the ERCB via the Well Test Capture system in accordance with Section 11.070 of the *Oil and Gas Conservation Regulations*.

4.6.10.2 Gas Wells producing under the self-declared commingling process

Gas wells producing under self-declared commingling in accordance with Section 3.051(2) of the *Oil and Gas Conservation Regulations* require produced fluid analyses for the commingled production stream, and pressure and productivity testing. These testing requirements must be met on a well basis. The type and extent of the pressure and productivity testing for these wells is dependent upon the average operating day flow rate of the commingled well for the first 3 calendar months with production immediately following the well being commingled under the self declared process (((total production during the 3 months) / (total hours on production during those 3 months)) x (24 hour / day)).

If the gas well's average operating day flow rate for the first 3 calendar months with production immediately following the well being commingled under the self declared process is less than or equal to 50 10^3 m^3/ operating day, then only an initial pressure and fluid analysis for the commingled production interval is required. No individual pool pressures or subsequent pressures are required, nor is any deliverability testing required. However, if any such tests are conducted on wells producing under the self declared commingling process, the test data and analyses must be submitted to the ERCB via the Well Test Capture system in

accordance with Sections 11.005 and 11.120 of the *Oil and Gas Conservation Regulations* and Section 4.9 of this directive.

If the gas well's average operating day flow rate for the first 3 calendar months with production immediately following the well being commingled under the self declared process is greater than 50 10^3 m^3/ operating day, then some form of production testing must be conducted, or be available from previous tests on the well, to identify the pools or zones contributing to flow from the well. This production testing may take the form of historic production from the pool, traditional segregated pool flow or deliverability testing, or flow meter testing where such testing can be used to reliably determine the contribution to flow of the individual pools under the flow conditions present in the wellbore. Where flow meter logs are used, both the log data and an interpretation of the data must be filed together with the ERCB. The feasibility of the electronic submission of flow log data and interpretations to WTC is being investigated, but presently such information must be submitted in paper copy to the ERCB in the same manner that other well logs are filed. For each pool or zone contributing 35 10^3 m^3/ operating day or more to the 3 month average rate, an initial segregated pressure and fluid analyses must be submitted. If the well producing more than 50 10^3 m^3/ operating day has no pool or zone contributing 35 10^3 m^3/ operating day or more, then the major contributing zone, regardless of flow rate, requires an initial segregated pressure and fluid analyses to be submitted. Beyond the production testing required conducted to identify the dominant productive pools or zones, there is no further deliverability testing required for these wells commingled in accordance with the self declared process.

Ongoing annual pressures on the commingled well are required for all self-declared commingled gas wells that initially produced more than 50 10^3 m^3/ operating day. This requirement does not change when the total well rate drops to or below 50 10^3 m^3/ operating day.

If self-declared commingled production includes gas from coals or shales, the data requirements for control wells must also be met in accordance with Section 7.025 of the *Oil and Gas Conservation Regulations* (*OGCR*) and, for gas production from coals, *Directive 062: Coalbed Methane Control Well Requirements and Related Matters*.

4.6.10.3 Oil Wells producing under the self-declared commingling process

Oil wells commingling under the self-declared process are subject to the standard commingled oil well testing requirements.

4.6.11 Recommended Practices for Pressure Survey Design

Some additional practices that should be considered when designing (coordinating) a pool pressure survey are listed below. However, it is always important to keep in mind what this pressure data will be used for; what we are trying to find out about this pool.

- Whenever possible, pressure surveys should be scheduled to coincide with planned well down time.
- It is important to return the well as close to producing conditions as possible, or wait until the transient introduced has dissipated; or, when fluid is used to "kill" a well in preparation for testing, that fluid should be swabbed back prior to commencement of the test.
- In pools where both primary and enhanced recovery schemes are operating, sufficient pressure data should be taken to determine the pressure for both recovery mechanisms,

until enhanced recovery has been deemed "not feasible" for the primary area.

- The use of injection wells as candidates for pressure testing usually results in a higher pressure and would not be acceptable for determining the pressure in the producing zone or assessing whether producing wells are in compliance with Minimum Operating Pressures (MOP). However, if pressure transient analysis or previously correlated data, indicates a pressure from an injector is representative of the producing area of the pool, this may be deemed acceptable. This will usually occur when injection fluid is taken on vacuum (e.g., reef type pools).
- Survey coverage early in the life of an enhanced recovery scheme with a patterned flood generally requires a representative pressure test on a producing well in each pattern. Later in the life of the scheme, selection should be based on performance and previous pressure information.
- Pressure sinks or highs in pressure maintenance schemes should be monitored each year until the problem is corrected.
- Shut-in wells within the producing area of a pool, may be good candidates for pressure observation providing they are in good communication with the productive area of the pool. See Section 4.5.9 for more information.
- An initial pressure is often relatively simple and inexpensive to obtain; therefore, it should be taken for all wells, including infill wells, whenever practical.
- Pressure build-up data should be taken as early as possible in the producing life of a well. However, it is important to ensure that sufficient drawdown has occurred to establish an effective (practical) time to stabilization, as detailed in Section 5.1.

4.7 Drill Stem Tests

Requirement: There are no regulations requiring the conducting of drill stem tests; only the requirement to submit all drill stem tests conducted, in the DST.PAS electronic format.

All DSTs conducted, including misruns, must be submitted in the DST.PAS format (as defined in Appendix A). This includes reporting the closed chamber portion of a test. To submit a DST to fulfill the initial pressure survey requirement, set [PRPS] = (**I**)nitial in the TEST DATA section.

The type of DST to run is left up to the licensee/operator to gather the information they need. The ERCB requires that all regulations regarding safety and environmental issues be followed or any other operational concerns addressed.

The ERCB administers the DSTs that have been conducted, according to the information on the ERCB Form WR-2. The licensee has 30 days from the finished drilling date of the well, to submit these reports. Failure to do so will result in enforcement action in accordance with *Directive 019*.

4.8 Fluid Analyses

Requirement: All fluid analyses on samples gathered at a well, which are representative of the formation (not mixed stream), must be submitted electronically in the appropriate PAS file. If multiple samples/analyses are done, all must be submitted. In addition, fluid analyses on each mixed stream (commingled) fluid that is produced from each well commingling within a development entity or under the self-declared

commingling process in accordance with Section 3.051 of the *Oil and Gas Conservation Regulations* must be submitted electronically in the appropriate PAS file format.

Further, all gas and/or fluid samples analyzed in conjunction with the following tests must be submitted:

- DSTs conducted on wells outside of existing pools, as per the current ERCB pool order
  - fluid analysis is required if fluid is recovered during the test
  - gas analysis is required if gas to surface during the test
- All deliverability tests require gas analysis for the fluid analysis correlation and must therefore be submitted:
  - with AOF on all wells drilled outside of existing pools, as per the current ERCB pool order
- Initial Pressure Tests conducted on wells outside of existing pools, as per the current ERCB pool order:
  - gas analysis is required for oil and gas wells
  - fluid analysis is required for oil wells, and gas wells producing liquids OR, provide details regarding the source of analysis used in the correlation.
- Acoustic Well Sounder Tests require analysis information when calculating acoustic pressures:
  - gas analysis is required for all acoustic tests,
  - fluid analysis is required when fluids are present in the wellbore OR, provide details regarding the source of analysis used in the correlation.
- Pressure Transient Analysis requires gas and fluid properties for calculations. OR, provide details regarding the source of analysis used in the correlation.
- Each well producing from a development entity or commingling under the self-declared process must have fluid analyses on each mixed stream (commingled) fluid that is produced from the well submitted to the ERCB in accordance with Section 11.070(2) of the *Oil and Gas Conservation Regulations*. These analyses are required, among other reasons, to verify that the well production contains no H_2S and thereby qualifies for commingling under these processes, and must be conducted within 30 days of the well commencing commingled production under Section 3.051 of the *Oil and Gas Conservation Regulations*.
- Wells producing under the self-declared process in which the well's average operating day flow rate for the first 3 calendar months with production immediately following the well being commingled under the self declared process is greater than or equal to 50 10^3 m^3/ operating day requires some individual pool fluid analyses. Analyses of each produced fluid from each individual pool contributing greater than 35 10^3 m^3/ operating day to the total flow, or the major contributing pool if no individual pool is contributing greater than 35 10^3 m^3/ operating day, must be submitted to the ERCB. Any analyses required by this section must be conducted within 30 days of the well commencing production in accordance with Section 3.051(2) of the *Oil and Gas Conservation Regulations*.

4.9 Submission Requirements

Requirement: Licensees/Operators are required to submit to the ERCB, in the appropriate electronic .PAS format, all pressure and deliverability tests, DSTs, and

fluid analyses, including those not required by this guide, as per Sections 11.050 and 11.120 of the *Oil and Gas Conservation Regulations*, and in Appendix A:WTC PAS File Submission Formats, Business Rules, and Implications for Noncompliance.

This includes tests conducted within designated oil sands areas. Only those tests conducted under controlled conditions need be filed, including; drawdown tests, interference tests, two-rate tests, segregation tests, reservoir limits tests, injection or fall-off tests, and so on. A casual reading of a wellhead pressure with a portable dial gauge or a pumping fluid level need not be reported. Likewise, if you have conducted a test that failed and has no useful information, it need not be submitted, with the exception of DSTs, where all tests must be submitted including misruns.

Where the ERCB determines that a test has been conducted and not submitted, the matter becomes a noncompliance issue, subject to the measures detailed in Section 6 of this directive.

If an application has been submitted, referencing a pressure that has not been submitted, the licensee will receive a notice letter starting the compliance process. The application will be considered deficient, and processing will be delayed until all data is available.

If test data pertinent to a land sale has not been submitted:

- if the sale is pending, sale of the property in question may be deferred until all data is available, or
- if the sale has occurred, the results may be reversed and the property re-issued for sale when all data is available.

For gas, oil, or water analysis, only those samples gathered from a well need be submitted.

4.9.1 Timing of Submissions

Requirement:

- **All pressure and deliverability tests must be submitted within 90 days of completing the field work.**
- **All DSTs must be submitted within 30 days of the finished drilling date.**
- **All gas and fluid analysis must be submitted within 45 days of completing the test.**

This time is provided for the licensee/operator to complete analysis and review the results. Compliance follow-up on initial pressure and deliverability tests will begin after production has been reported in three consecutive calendar months. Although the mechanism for ERCB to administer initial tests is the first three consecutive months of production reported, the 90-day rule is still in effect. If documentation is provided that indicates a well was tested and the data is not in the ERCB records, you will be required to submit that test even though the well has not commenced production.

Any annual tests not received by 31 March of the following year, will be deemed in noncompliance and have consequences assessed. This ensures that tests conducted in November or December have the full 3 months to compile and submit the test results.

Compliance follow-up on DSTs will commence 30 days from the finished drilling date for each individual well.

4.9.2 Reporting Formats

All reports must be submitted electronically in the current version of the .PAS format as defined in Appendix A: WTC PAS File Submission Formats, Business Rules, and Implications for Noncompliance.

The most current version is always available from the links in Appendix A.

An electronic report must include an image file, with any charts and graphs, dialogue, explanations, and any parameters used in the analysis and results that have not been included in the PAS file.

Test/survey reports should contain a complete record of any event that may have affected the quality or interpretation of the data. The objective is to provide sufficient information for anyone using the data to be able to assess its reliability. All test results should be compared with the results of previous tests, if applicable, and both should be reported. Where anomalous data is encountered, explanations should be provided, or the well should be re-tested.

When tests have been run only for the licensee's use, and are not intended to fulfill survey requirements, within the ~Test Data Section of the appropriate PAS file, setting the [PRPS] = (O)ther, will turn-off the "acceptable survey" edits and therefore only be recognized as "information only". This will ensure that quality requirements are not applied, and the licensee/operator not requested to provide further validation and analysis of data. It is further recommended that whenever possible the reason for a test being submitted as "information only", be documented in the [PRGC] (Comment on Pressure) filed of the PAS file.

Although there are no standard requirements for bitumen wells in designated oil sands areas, all tests conducted on these wells must still be submitted to the ERCB. All of the gas well testing requirements and provisions of this directive apply to gas wells in the designated oil sands areas.

5 Acceptable Test Standards

The manner in which tests/surveys are conducted and reported is always critical to the value of the data obtained. This section defines the quality standards required for tests to fulfill survey requirements.

The "Acceptable Survey Standards" for required tests have been translated into edits which are defined in Appendix A: WTC PAS File Submission Formats, Business Rules, and Implications for Noncompliance.

Some edits are critical, which will result in the file being rejected. Other edits that require some interpretation have been identified as non-critical and will not cause the file to be rejected. These edits will be administered by an audit process. Tests not meant to fulfill any requirement can be indicated in the Test Data Section of the appropriate PAS file, and the "acceptable survey" criterion will not be applied. This can be indicated by setting [PRPS] = (O)ther within the ~Test Data Section of the appropriate PAS file.

All tests conducted must still be submitted to the ERCB, as per Section 11.005 and 11.120 of the *Oil and Gas Conservation Regulations*, as defined in Section 2.0 of this directive. All submissions must be made electronically as defined in Appendix A: WTC PAS File Submission Formats, Business Rules, and Implications for Noncompliance.

5.1 Obtaining a Stabilized Reservoir Pressure

A major problem with pressure data is determining whether or not the pressure is representative of a stabilized reservoir pressure. If a transient pressure test is being submitted to fulfill requirements, the PAS file must either include analysis, or the raw data must reflect a stabilized reservoir pressure. For most purposes, a "stabilized reservoir pressure" is defined as a pressure that does not build over 2 kPa/hour during a 6 hour period.

The following four methods are acceptable for obtaining pressures that are representative of stabilized shut-in reservoir pressures, in order of preference. Further details of these methods are included below:

1) Measure sufficient transient data to reliably extrapolate to a stabilized reservoir pressure (P_R). See ERCB *Directive 034* for more information. Transient tests must be submitted with analysis, or they will be rejected as deficient (note: for a flow and build-up test, the shut in should be four times the flow period).
2) Measure pressure build-up until the change in pressure is less than or equal to 2 kPa/hour, over a 6 hour period.
3) Measure a static pressure after a shut-in sufficient to reach a stabilized pressure, as determined from previous transient data on this well (if previous transient data indicates a shut-in in excess of 14 days is required to reach a stabilized pressure, the ERCB expects the licensee/operator to use the appropriate shut-in, but relief from testing requirements should be considered as discussed in Section 4.6.3).
4) Measure a static pressure after a shut-in time of at least 14 days, where no transient data is available.

   Ensuring that a stabilized pressure is obtained for low permeability or commingled pools may be challenging even when these methods are used. However, while enhancements to testing requirements for such reservoir situations may be required, the use of the above methods will still help ensure that reasonably stabalized measurements are obtained.

5.1.1 Transient Pressure Tests with Analysis

The first method involves gathering and extrapolating transient data. This is considered the most efficient method of determining a stabilized shut-in reservoir pressure. Transient data can be costly to obtain; but it has the added advantage of providing estimates of reservoir rock properties and completion effectiveness.

With electronic submission, a critical edit will check for an average reservoir pressure (P_R). A correction to average reservoir pressure is required in a producing pool P* or the False pressure from the Horner Plot is not representative of the average reservoir pressure and will be corrected using the MBH techniques as described in ERCB *Directive 034*.

5.1.2 Transient Pressure Tests without Analysis

The second method involves conducting a transient test (extended measurement of buildup) that has reached pressure stabilization. The acceptable pressure change rate indicating stability would be less than 2 kPa per hour. However this rate of change may not indicate stabilization in systems with dual porosity/permeability, fractures, stratified layers, phase separation in the wellbore, etc. If these circumstances exist, 2kPa per hour should not be used.

The following critical edits determine if a stabilized reservoir pressure has been reached. Tests submitted without analysis that do not meet the criteria will be rejected:

- Get the values reported as:
  - RESULTS SUMMARY [PMPP] (representative bottomhole pressure at MPP) for AWS tests, or
  - RESULTS SUMMARY [PRGA] (last measured or representative pressure at stop depth) for TRG tests
- Match these values to the acoustic data table, or the gauge 1 (source gauge) data table.
- The difference in pressure over the six hours prior to this value must be equal to or less than 12 kPa (2 kPa per hour as defined in Section 5.1 of this directive).
- If a pressure reading cannot be found at the 6 hour interval prior to [PMPP] or [PRGA], the edit will look for the next previous reading and determine if the 2 kPa/hr limit has been met.

IMPORTANT: If this program cannot match the value reported in RESULTS SUMMARY [PMPP] or [PRGA] in the raw data table, the file will be rejected.

5.1.3 Static Pressure Tests

The final two methods involve static pressure measurements, which can be the most cost-effective method of survey; but they are of little value if the shut-in period is too short, and the well build-up character is unknown.

For the third method, the time required to obtain a stabilized reservoir pressure must be determined from previous transient data, conducted on the same well. The full time to reach theoretic stabilization calculated as part of the transient analysis is not required. For most reservoir management/ development applications an effective time to stabilization, that is at least 95 per cent of the true (fully built up) stabilized pressure, is satisfactory. The effective time to stabilization can be determined by taking 95 per cent of the extrapolated pressure and determining the time it took to reach that point. This time may change during the life of the well and may need to be re-established, depending upon depletion, re-completions, well treatments, etc. An initial pressure transient test does not usually provide a basis for an establishing build-up time to a stable pressure after the well has produced for several months. The initial test time is very short (small radius of investigation) in relation to the long production time on subsequent tests after the well has produced commercially. Consequently, the time to reach a stable pressure can be much greater than observed on an initial test.

In some cases, the shut-in time needed to reach stabilization can be estimated from offset wells and applied to the current test as a guide to determine a necessary shut-in time or when to terminate the test. However, this is only applicable where reservoir characteristics are very similar, and the expected time to stabilization would be the same. In general, it would not be acceptable to use only the shut-in time from an offset well to determine the length of time to conduct a static pressure test.

The fourth method also involves a static measurement but in this case there is no supporting analysis. Therefore, a minimum shut-in time of 14 days was selected because it should provide adequate pressure build-up for most reservoirs. An exception to this would be in enhanced recovery schemes with a Minimum Operating Pressure (MOP). In these instances, a static test may be accepted, if it indicated the well/scheme was operating above MOP, regardless of the length of shut-in time. However, this method must be approved by ERCB

staff, and these pressures should not be used for reservoir calculations or modeling as they are not representative of the reservoir pressure (this is an example of designing a test for a specific purpose).

When conducting an initial static pressure, remember that drilling, completion, and cleanup operations create some drawdown, or may be overbalanced. However, since production from the well has been minimal, a 14-day shut-in is probably not required for an initial static pressure survey. Please indicate that the pressure is stable on the report in the RESULTS-SUMMARY section, under [PRGC] (Comment on Pressure) element. Also, an initial static gradient with a longer stop at bottom (minimum 2 hours) would be acceptable, providing it indicates pressure stabilization.

5.1.3.1 Surface Indication of Static Pressure

In certain circumstances, a stabilized pressure can also be obtained by monitoring the surface pressure until it stabilizes then measures or calculates the down-hole pressure. See Section 5.3 of this directive for further information.

5.2 Acoustic Testing

The most accurate way to measure subsurface pressure is direct measurement, by subsurface gauge. However, this method is very costly where pump and rods have been installed. In some cases it is acceptable to determine the bottomhole pressure indirectly using an acoustic method, providing the conditions detailed in this section of this directive are met.

Currently, about one quarter of all pressure surveys on oil wells are acoustic surveys. Unfortunately, the quality of acoustic surveys has varied considerably in the past, which has given them a poor reputation, and has limited their use in reservoir studies. *Directive 005: Calculating Subsurface Pressure via Fluid-Level Recorders* states "Experience has shown that the accuracy of subsurface pressures obtained from fluid-level measurements has, at times, proved questionable. Although the producing characteristics of many wells preclude great accuracy, the lack of accuracy can be attributed in many cases to improper data-gathering procedures, interpretation, and pressure calculation techniques".

There are practical ways to address these problems. First, the acoustic method should not be used where it is reasonable to run bottomhole gauges. Acoustics should be used for wells or circumstances where there is the best chance of obtaining meaningful pressure data. Second, the data gathering and field measurement procedures in *Directive 005* should be followed at all times. Finally every effort should be made to improve the accuracy of the calculations of subsurface pressures.

5.2.1 Verification of Acoustic Methods

Acoustic pressure surveys may be accepted if the following conditions are met:

- the pressure being taken is not an initial pressure,
- the fluid properties used for the calculation must be accurate and appropriately derived or confirmed by comparison to static gradient tests or PVT study data,
- the well does not produce water, OR
- the well produces water, but there is a 15 per cent or less difference between bottomhole pressures:

1) calculated by the acoustic method, assuming the influxed liquid column is all oil, compared to all water:

$$\frac{\text{(Initial Fluid Level – Final Fluid Level) * (Water Gradient – Reservoir Gradient)}}{\text{Extrapolated Pressure at MPP}}$$

OR

2) calculated by the acoustic method, and measured simultaneously using a bottomhole gauge.

When the acoustic method has been verified by method (1) or (2) above, it may be accepted for subsequent pressures in the well providing the same acoustic testing procedures are repeated. Method (1) is an effort to minimize the margin for error in situations where the well produces water. When verification is by (1), the submission should contain some discussion regarding the changing water influx. *Directive 005* addresses the fact that producing watercuts are seldom representative of water within the fluid column in the annulus, and should not be used when making calculations, as the watercut in the annular column will change over time. There are now models available in industry that take this factor into consideration. Another factor to consider is gas influx, which lowers the liquid level, thus driving water back into the formation.

When verification is by method (2), the submission should compare liquid levels between the acoustic and gauge tests, oil/water contacts at the end of the test, gradients used and their origin, and procedures used to control conditions to ensure consistent data for future tests. Although at first a gauge/acoustic validation may not appear to be within acceptable limits, once the above items have been addressed and final wellbore liquid content determined, a process can often be developed to calculate representative pressures for future use in that well. However, if subsequent tests are submitted where data does not appear reasonable, the verification will be considered invalid.

The verification results from wells in one pool cannot be used for wells in other pools; however, these results may be applied to other wells in the same pool that have similar reservoir characteristics. The acoustic method must be verified in a representative sample of wells before it will be routinely accepted in large multi-well pools. Again, it is important to follow the practices established in the verification process in future acoustic testing.

When conducting an acoustic test on a suspended well that experienced high watercut during production, it is important to determine if any water still exists in the wellbore. The length of time the well has been shut in and the reservoir characteristics can affect this determination. If the well is to remain suspended, but is a good representative pressure source, it may be advisable to remove the pump and rods and use the well for observation purposes, with subsurface gauge surveys.

Acoustic pressures should always be compared with the last pressure or pressure trend. Where anomalous results are indicated, the acoustic pressure may not be accepted, and further verification of the acoustic method may be required.

5.2.2 Acoustic Test Design

When designing and running an acoustic survey:

- A build-up survey is preferred over a static survey because it monitors the movement of the gas-liquid interface and wellhead pressures, and provides a better understanding of reservoir and wellbore dynamics. A build-up survey also provides additional information such as permeability and skin.

- Before conducting any acoustic survey on a producing well, the pumping fluid level must be determined. This practice significantly improves the chance of obtaining acceptable acoustic data. If the well is suspended or has been shut in for sometime this may not be possible.
- The presence or absence of foam should be established via a foam depression test.
- A sensible shot schedule should be used for build-up surveys. Typically a minimum of 20 to 30 points are required. They should be spaced logarithmically.
- When the pumping fluid level is high, depressing the gas-liquid interface prior to shut-in may be considered. In high GOR wells this can be done using the well's back pressure. In low GOR wells, forced fluid depression can be achieved by pumping nitrogen downhole.
- When an acoustic survey is to be conducted on a static well, more than one shot should be taken especially when single-channel equipment is used.
- The input data for the bottomhole calculation (fluid properties, average joint length, etc.) must be current and accurate.
- The practices in ERCB *Directive 005* must be followed.

It is a much more complicated engineering problem to calculate acoustic bottomhole pressures than to measure them with downhole recorders. It is important to have representative fluid compositions and final production rates. Also, the wellbore schematic, tubing tally, and directional survey data should be up-to-date. Finally, the casing pressures and fluid levels should be measured by experienced field personnel, using accurately calibrated and well-maintained equipment. This is just as important as ensuring the integrity of subsurface gauges.

In extenuating circumstances, where a pressure minimum is involved, the ERCB may consider a pressure that would be above MOP if the calculation assumed the wellbore liquid was all oil.

However, prior approval would be required for use of this method, and these pressures should not be included in determining an average scheme pressure.

5.3 Surface Pressure Tests

The method of monitoring surface pressures with memory digital surface recorders has been used by some companies recently, as a means of determining reservoir pressure stabilization. This method assumes that stabilization of pressure at surface is indicative of stabilization downhole. The bottomhole reservoir pressure is then determined using acoustic fluid level data obtained once stabilization at surface has occurred. As in Section 5.2.2, the integrity of the equipment used to measure surface pressure is paramount to the success of your test.

This method of monitoring reservoir pressure stabilization is acceptable in many cases, providing:

- it is not an initial pressure survey,
- the minimum of an initial and final fluid level shot are conducted and reported, including all parameters required for an acoustic survey, and
- the test meets all criteria defined for an acoustic test in Section 5.2.

5.4 Permanent Downhole Gauges

In instances where it is necessary to monitor the pressure in a particular well on a frequent basis, it may be desirable to install a permanent type of gauge downhole. There are a number of these gauges on the market, but problems are often experienced if a maintenance program is not followed. Further information on maintenance of these gauges can be obtained from their respective manufacturers. Tests submitted from this method must meet all standards of reasonableness. See Section 8.0 for calibration requirements of these gauges.

Pressure data obtained from these gauges must be reported in the appropriate electronic format defined in Appendix A: WTC PAS File Submission Formats, Business Rules, and Implications for Noncompliance.

5.5 Drill Stem Tests (DSTs)

As in the past, DSTs must be conducted adhering to all environmental and safety requirements. All DSTs conducted are required to be submitted within 30 days of the finished drilling date of the well, as per Section 11.100 of the *Oil and Gas Conservation Regulations*. This requirement includes misrun tests, which often provide some useable information.

The responsibility for administering DSTs at the ERCB rests with the Well Test Section of the Information Collection and Dissemination Group. All tests must be submitted in the DST.PAS electronic format as detailed in Appendix A. This format also includes all closed chamber data that may have been collected.

The ERCB will administer compliance for submission of DSTs based on the information reported on ERCB form WR-2 with applicable details also recorded on the tour report forms. See Section 6 for further information on compliance administration.

5.5.1 DSTs Submitted as Initial Pressures

All of the following conditions should be met if a DST pressure is used to satisfy the initial pressure requirement:

- The test must be mechanically sound (no skidding, plugging, or loss of packer seat).
- The extrapolated pressures (P*) from any two shut-in periods should be within one per cent of each other, and clearly different from the hydrostatic pressure.
- The last measured pressure and the extrapolated pressure (P*) from the final shut-in period **must** be within five per cent of each other.
- If the DST is being submitted to fulfill a pressure survey requirement, within the ~TEST DATA section of the DST.PAS file, you must set [PRPS = (**I**)nitial. If you decide that you want a DST to fulfill your initial pressure survey requirement but you have already submitted the file with [PRPS] = (**O**)ther, you can resubmit the same DST.PAS file by changing the [PRPS] = (**I**)nitial. It will not be rejected as a duplicate, but more edits will be activated by this flag. Further a properly conducted DST meeting the requirements for an initial pressure can also count towards an annual pressure requirement, if the pool is listed in the annual survey schedule.

5.6 Wireline Formation Tests (WFTs)

The following provides some recommended practices that must be adhered to when using a WFT to obtain an initial pressure:

- The data must be interpreted by a qualified individual(s) using industry- accepted techniques. Special considerations exist with WFT interpretations and interpretation techniques applicable to the measured data. General Horner/Derivative techniques can be used, but the unique near-wellbore nature of these tests tends to invalidate basic Horner flow criteria.
- An on-record master calibration certificate for each transducer used must be available. Service companies must have their master calibration device compared to ERCB standards annually, as detailed in Section 8 of this directive.
- More than one single test within a particular reservoir must be taken. The wide variance on the test quality and pressure response between individual tests makes it critical to have at least two good quality pressures which fall within the repeatability specification of the tool.
- Reports for WFTs intended to fulfill a pressure requirement must be submitted in the electronic DST.PAS format, as per Appendix A. The electronic format for accepting WFT tests within the DST.PAS file is not available at this time. Reports for WFTs intended to fulfill a pressure requirement must be submitted at this time in paper format, addressed to the Well Test Section of the Information Collection and Dissemination Group of the ERCB.

The near wellbore nature of this kind of test needs special consideration in two main areas:

Depletion: Since the pressure distribution within a single zone very often differs significantly from test to test, due to preferential depletion in a developed reservoir, it is not practical to assign a single pressure to such a zone. While it is accepted that the requirements pertain to new pools where this should not be seen, more variation is observed across a single zone than is historically seen from a conventional single test that straddles the entire zone that provides a single average pressure value. A single zone with the presence of gas, oil, and water will yield a pressure profile that does not lend itself to an easy mathematical function which describes a single, average pressure. A general technique to convert several pressures to a single value needs to be defined.

Supercharging: The near wellbore nature of these tests often yields pressures which are obviously too high when compared to other nearby pressures obtained through conventional means. The discerning factor is near wellbore permeability. Experience has shown that near the one millidarcy permeability level, as measured by WFT/MDT type tools, measured pressures are very likely to be affected by the excess pressure of mud filtrate invasion that has not had sufficient time to re-stabilize because of low permeability. Pressure tests with this problem will appear and interpret completely normal. However, due to the very shallow depth of investigation and the excess pressure from mud filtrate invasion, the pressure will not be representative of the formation, but some value higher than formation pressure.

Proper interpretive techniques are available to recognize but not correct for pressures that appear too high. This further emphasizes the need for experienced personnel.

5.7 Surface Acquired Fall-Off Tests (Data Frac, Mini Frac, Hydraulic Fracture)

In low permeability reservoirs, DST and/or a pre-stimulation test may not provide adequate inflow and/or pressure buildup to determine a reasonable initial reservoir pressure. Fracture fall-off pressure data may provide an alternative method of determining an acceptable reservoir pressure. A dead-leg (full column of fluid) is often used to monitor frac fall-off data and using this method of measurement can provide reasonably accurate and confident bottomhole pressure determination. However, this method is acceptable only when

conventional testing in not possible and extreme care is taken to ensure representative results. Whenever possible, a bottomhole pressure should be obtained by some other method to validate the results.

An operator must verify and substantiate that the bottomhole pressures have been properly calculated and pressures are representative of reasonable values. If a pressure can be proven to be representative, the ERCB may accept the pressure to fulfill survey requirements. These tests are to be reported electronically in the AWS.PAS file format.

The following conditions must be met if surface data from a frac fall-off are used to determine an acceptable reservoir pressure:

- The column of fluid used is "dead fluid" and has no gas present.
- The density of the frac fluid being used is known and samples are obtained and analyzed.
- The well does not go on vacuum (hydrostatic pressure is less than reservoir pressure).
- Fluid levels may be determined but further acoustic validation is required.
- The surface gauges used must have reasonable resolution and accuracy and have been properly calibrated.
- The wellbore has less than 10 per cent of its volume saturated with a proppant even with properly calculated slurry densities; corrections can be erroneous (unless a dead-leg is used).
- The final fall-off pressure and the extrapolated pressures are within five per cent of each other. **The analytical method for extrapolations and comparison must be validated. If a flow regime can be identified the appropriate analytical method of analysis can then be applied.**
- The operator must verify and substantiate that the bottomhole pressures have been properly calculated and are representative of reasonable values. The submission must include a discussion of the methods used and the relevance of the pressure measurement.

Note: Fall-off tests from large hydraulic fracture treatments may require an unreasonable long shut-in time to obtain sufficient information to determine a representative pressure.

6 Compliance to the Minimum Requirements

ERCB regulatory requirements are those rules that an operator has a legal obligation to meet and against which the ERCB may take enforcement action in cases of noncompliance. The ERCB's enforcement process is specified in *Directive 019.*

6.1 Compliance Tools and Administration

To facilitate compliance administration, the ERCB has posted the following files on its website. File (1) is updated weekly, File (2) is updated monthly, and include the following information:

1) A list of all outstanding wells that require initial pressure or deliverability tests, including
   - licensee,
   - UWI,
   - notice date
   - due date

- interval top
- interval base
- type of test required (Initial pressure test or deliverability test), and
- well license number

2) The annual survey schedules for oil and gas pools, including
   - field and pool names and codes,
   - coordinating operators,
   - survey frequency,
   - year survey due, and
   - status (fulfilled, outstanding, partially fulfilled, etc.).

6.2 Extensions to Deadlines

If you are unable to meet the deadline indicated in the notice letter, an extension can be requested by notifying ERCB Well Test staff as per Appendix C.

6.3 Licensees' Responsibilities

All licensee/operators will receive a warning letter advising that survey requirements must be fulfilled or "satisfactorily addressed" by a specified date. For annual survey requirements the notice letters go out in early November and the coordinating operator actually has until 1 April of the following year before any consequences are assessed. For initial pressures and deliverability testing, the warning letters provide 30 days to fulfill or address survey requirements.

"Satisfactorily addressed" can range from a detailed submission requesting waiver or exemption of the survey requirement (complete with substantiating information), to a telephone call requesting an extension to the deadline. To assist in determining responsibility in these cases, the ERCB Well Test staff keep a complete log of all incoming calls.

The company receiving a notice letter is responsible for fulfilling the survey requirement, addressing the requirement, or notifying the ERCB that they are no longer responsible for this well. All warning letters clearly state that failure to respond within the specified timeframe will result in the assessment of a noncompliance fee of $1000.00. The assessment of this fee involves considerable administrative processes from tracking the delinquent surveys to generating the invoices and subsequent letters, and financial accounting procedures.

7 Special Testing Situations

Listed below are examples of situations where special testing may be required by the ERCB. The need for special testing may be determined through the ERCB's application and approval process. However, the ERCB also reserves the right to require special testing, where it considers it appropriate and reasonable to do so. Special testing would usually be a temporary increase in the number of tests, and may involve specific procedures. However, in some cases, where there are environmental concerns, reduced testing and more operational restrictions may apply.

- Pool definition and development
  - reserves assignment
  - enhanced recovery evaluation
  - equity issues

  - well spacing
- Facilities approval
- Production rate controls
  - conservation concerns
  - equity issues
  - concurrent production
  - off target wells
- Anticipated enhanced recovery schemes
  - oil pools above the bubble point
  - retrograde gas pools (above the dew point)
- Operating enhanced recovery schemes
  - gas cycling
  - solvent floods
  - immiscible gas floods
  - $C0_2$ & N_2 floods
  - polymer floods
  - waterfloods
- Enhanced recovery schemes
  - representation in pattern floods
  - representation in areas of concern (pressures below/near MOP, high voidage)
- Other gas or water injection circumstances that may require more extensive testing
  - gas storage schemes
  - acid gas disposal schemes
  - water disposal
- Wellbore configurations
  - multi-lateral wells
  - dual completions
- Environmental concerns
  - safety
  - odours, noise, visual
  - flaring sour gas
- Oil sands
  - equity issues (gas/bitumen and offset oil sands lease holders)
  - mini-frac tests
- Special Requirements/Relaxation that has been granted following application

7.1 Control Wells for Gas Production from Coal and Shale

Section 7.025 of the *Oil and Gas Conservation Regulations* lays out the requirement to have control wells in place prior to the production of gas from coal or shale, and Section 11.145 of the *Oil and Gas Conservation Regulations* describes the testing requirements for these control wells. These control well requirements must be met for all coal and shale

developments, whether or not commingling is occurring. Also, control wells must be in place for any and all CBM and shale gas developments, even if the development is small in scale.

While requirements for shale gas control wells are in place as referenced above, there are few shale gas control wells established to date, and further elaboration on the testing requirements for these wells is still under development. Therefore, only CBM control wells, which are more prevalent and of particular current interest, will be dealt with in this edition of *Directive 040*. Additional discussion of shale control wells can be found on the ERCB Web site www.ercb.ca.

In summary, CBM control wells must be established and data obtained from the wells as follows:

- One valid CBM desorption control well for every CBM zone is required within 5 km of each well in which CBM production is proposed.
- One valid control CBM pressure and flow well for every CBM zone is required within 3 km of each well in which CBM production is proposed.

If there is not a desorption control well and a pressure and flow control well for each CBM zone to be developed within the prescribed radiuses, an operator must establish the required control well(s) prior to commencing gas production from coal. If a control well does not have data for all CBM zones being developed in the area, a second control well will be required to collect data on the missing zones. An explanation of the ERCB's criteria for designating CBM zones is available on the ERCB's Web site www.ercb.ca under Industry Zone : Rules, Regulations, Requirements : Commingling : Management of Commingling in the Wellbore.

The ERCB has developed a control well list, also available on the Web site www.ercb.ca, to assist operators in determining whether a control well is required. If a control well is required, the operator must establish an ERCB-validated control well prior to commencing production in any well with completions in coal.

A well licensee must request validation of a control well by filling out the Coalbed Methane Desorption Control Well form and/or Coalbed Methane Pressure and Flow Control Well form available on the Web site www.ercb.ca. These forms must be submitted to the ERCB's Resources Applications Group, Attention: Control Well Coordinator. Upon receipt of these forms, the ERCB will evaluate the well and test zones, advise the licensee if the well and zones are valid and, if so, list the control well and CBM zones on the control well list.

Additional information on CBM desorption control wells is available on the Web site www.ercb.ca.

With respect to CBM pressure and flow control wells, the following testing requirements must be met:

- The control well must have coal completions only.
- Initial analyses of each produced fluid must be conducted for the combined flow stream and submitted to the ERCB using the ERCB Well Test Capture system within the timeframe specified in
  - Section 4.8 for wells commingled using the development entity process or the self-declared commingling process and wells commingled under Southeastern Alberta Order No. MU 7490 or any successor order(s), or
  - Section 4.9.1 for single coal zone wells.

- An initial segregated pressure for each coal zone to be covered by the control well must be collected and submitted to the ERCB within four months of the validation of the control well, using the ERCB Well Test Capture system. Segregated pressure tests must be conducted on the coal zones defined by the ERCB and available on the ERCB Web site www.ercb.ca.
- Initial flow meter logs for each CBM control well must be conducted over all coal zones to be covered by the control well and submitted to the ERCB within 4 months of the validation of the control well. Alternatively, segregated individual flow tests on each individual coal zone may be run and submitted.
- Annual (each calendar year) segregated pressures for each coal zone must be collected and submitted to the ERCB using the ERCB Well Test Capture system within the timeframe specified in Section 4.9.1. Segregated pressure tests must be conducted on the coal zones defined by the ERCB and available on the ERCB Web site www.ercb.ca.
- Annual (each calendar year) flow meter logs for each CBM control well must be conducted and submitted to the ERCB within one month of the flow meter log run date. Alternatively, segregated individual flow tests on each individual coal zone may be run and submitted.
- The control well must remain on production from coals only until it has been replaced by an acceptable alternative ERCB-validated control well.
- Control well obligations continue for the life of the CBM development that the control well supports or until the ERCB changes the control well requirements.
- If the control well is completed in non-coal strata, the non-coal completions must remain segregated from the coal zones at all times.
- Flow meter logs should be collected after the well has been completed and cleaned up.
- If completed coal zones are not tested correctly, the ERCB may require retesting of the well. The licensee must retest in accordance with ERCB instructions to retain validation of control well status for the coal zones completed in the well.
- To reflect coal production only, the CBMCLS (23) fluid code must be used to report control well production to the Petroleum Registry of Alberta.
- With submission of the control well form for designating a control well, the licensee acknowledges that the control well and all information relating to that well is no longer confidential as of the designation.
- The ERCB will handle all incidents of noncompliance in accordance with *Directive 019.*

The above requirements were developed primarily for coals that produce little or no water. Mannville and other coals that produce water may not be able to meet all of these testing requirements (e.g. initial flow testing). In these cases, requests for relief from specific control well testing requirements, including support for the requested relief, should be submitted to the ERCB at the same time that the pressure and flow control well validation request is made. No exemptions to the requirement for control wells will be granted, but the ERCB will consider requests for relief from specific control well requirements for coal zones that produce water.

8 Measurement

This section provides a general discussion of certain practices to be considered in the running and maintenance of pressure measurement devices.

8.1 Gauge Information

- A gauge should be chosen so that the expected value of the pressure to be measured is between 60 and 90 per cent of the gauge's rated pressure range.
- Mechanical gauges should be flexed before and after each pressure measurement to ensure the pressure recorder is functioning properly.
- Gauges should be run in tandem to track the performance of both gauges and improve the reliability of the measurements. The differences in pressure and temperature between the two gauges should always be compared.
- If a gauge shows temperature sensitivity, or if the reservoir temperature is above 95°C, an acceptable bath calibration should be available so that allowances can be made for the effects of temperature in the subsequent calculations.
- When the gauge is returned to the surface, it should be set at the depth reference elevations again, at the top of the casing flange where the wireline counter was initially zeroed. This gives a check on the accuracy of the depth measuring device. The discrepancy in counter readings at this point should not be substantially greater than indicated in the following table (in metres):

Discrepancy	0.3	0.6	1.2	2.1	4.2	7.5
Run Depth	600	1200	1800	2400	3000	3600

Where a greater discrepancy is observed, any conditions that may have caused slip and elastic deformation of the wireline should be reported.

- The maximum temperature thermometer should be read, and the maximum temperature recorded, immediately after the bomb has been retrieved from the well.
- When gauges can not be run down to the mid-point of the producing interval, the gauges should be run as low in the well as is safely possible. Under such conditions the determination of the wellbore gradient at run depth is critical to the extrapolation of run depth pressure to bottomhole pressure (at MPP). Making stops at 30 metre intervals over the last 150 metres can help to get an accurate gradient. However, be sure the gradient you use for this extrapolation makes sense (e.g., if the gauges have not encountered fluid in the wellbore of an oil well, it may not be appropriate to assume a gas gradient to MPP).

8.2 Surface Pressure Readings

The casing and tubing pressures should always be read with a deadweight tester and recorded. These deadweight testers must be calibrated in accordance with Section 11.110 of the *Oil and Gas Conservation Regulations*.

8.3 Gauge Calibrations

In order to maintain accuracy and a comparative baseline in the measurement of subsurface pressures, the ERCB requires that all gauges be calibrated in accordance with Section 11.110 of the *Oil and Gas Conservation Regulations*.

Licensees/Operators are referred to the manufacturers' manuals for assistance in understanding the details of calibrations. The service companies are required to maintain adequate calibration history on each gauge, and be prepared to submit this data to the ERCB upon request. However, the date of last calibration is required on every pressure test report. All deadweight testers used for calibration must have a valid annual comparison to an

accredited standard in accordance with Section 11.110 of the *Oil and Gas Conservation Regulations*.

8.3.1 Calibration Standards

The calibration results should be examined to determine whether the gauge is maintaining accurate behaviour, based on the following criteria:

- For mechanical gauges, the indicated pressure at 50.0-mm deflection should vary from the results of the previous calibration by not more than 0.25 per cent of the range of the gauge (theoretical accuracy limit). If it does, the deflections from individual calibration steps should be examined for consistency. If the deflections are consistent, a new trend may be assumed to have been established, and the calibration is satisfactory. If not, the calibration should be rejected and the gauge re-calibrated.

- The criterion for adequate temperature compensation is based on a comparison between hot-liquid-bath and air calibrations. The difference should not exceed 0.25 per cent of the gauge's range. Whether or not it does so may be determined by substituting the deflections from the bath calibration into the equation obtained from the air calibration, then calculating the difference between the resulting bath calibration pressure and the air calibration pressure. If the difference is greater than the gauge's theoretical accuracy, the instrument may be considered temperature-sensitive at that pressure. In this way, it may be determined whether the gauge is influenced by the calibration temperature, and through what pressure range temperature sensitivity is occurring. The gauge owner is then expected to use the bath calibration to calculate the results of pressure surveys when conditions are similar to those in the bath calibration.

- Electronic gauges require the same frequency and accuracy of calibration as that specified for mechanical gauges.

8.3.2 Calibration of Permanent Gauges

In instances where a permanent gauge is installed downhole, the three-month calibration requirement defeats the purpose of a permanent gauge. These gauges can provide good data. However, problems are often experienced over time if a maintenance program is not followed, with periodic checks to ensure the ongoing accuracy of the gauge. When a procedure is planned that requires pulling a permanent gauge, the opportunity must be used to calibrate the gauge. Further information on maintenance of these gauges can be obtained from their respective manufacturers.

8.3.3 Special Calibration Notes

The following comments are offered as further clarification of ERCB's policy with regard to pressure-gauge calibration:

- It is desirable to calibrate a gauge in, as nearly as possible, the same conditions as prevail in the field.
- At least two sets of readings should be obtained for each calibration. If consistency between the two is not evident, the gauge should be closely examined for damage.
- Sets of calibration steps should be spread out across the chart so that any damage to the chart carrier will become apparent.

Appendix A: WTC PAS File Submission Formats, Business Rules, and Implications for Noncompliance

1 Background

The ERCB needs to ensure that the quality and usefulness of the data that it requires is maintained. Industry has previously voiced concerns about the quality of well tests submitted to the ERCB, the inconsistency in engineering practices used to meet testing and submission requirements, and the need for improved enforcement of such requirements.

The discussion in this Appendix A addresses a number of areas where well testing often fails to meet the intent of the requirements. The PAS file formats that must be used for all well test data submission covered by this directive are available on the ERCB Web site by following the links at the end of this appendix.

The implementation of the development entity and self-declared commingling processes, and control well requirements for production from coal and shale have introduced changes to testing requirements for these situations. Further work on business rules and PAS file structure is likely necessary and will be incorporated into *Directive 040* when the final analysis is completed.

2 General Well Testing References

ERCB *Directive 040* cites ERCB *Directive 034* and *Directive 005* in many places for the technical rules of practice to be followed when designing, conducting, and interpreting gas and oil well deliverability and subsurface pressure tests.

Industry is reminded that these three guides continue to be the main technical documents for testing procedures when conducting ERCB-required well tests, including the calculation of subsurface pressure measurements using fluid-level recorders.

Not meeting the requirements and rules of practice detailed in these directives could be considered noncompliance, leading to enforcement action being taken in accordance with *Directive 019*.

3 Initial Deliverability Testing of Gas Wells

3.1 Multipoint Deliverability Testing

Directive 040 Section 1: Introduction states that the well testing requirements defined in *Directive 040* are minimum requirements. Section 4.3.1: Recommended Practices for Gas Well Deliverability Tests provides guidelines for the type of deliverability test to be conducted and stipulates that "The initial test should be a multi-rate test when the anticipated extended AOFP of the well is 300 thousand cubic metres per day (10^3 m^3/d) (10.6 million standard cubic feet per day [mmscf/d]) or greater, or if turbulence is a factor." *Directive 034* is explicit in stating that in most cases a multipoint test should be conducted on new wells if little is known of the well's flow capacity or the reservoir's characteristics.

Deliverability tests other than the initial test are left to the licensee/operator to design and conduct in accordance with *Directive 040* and *Directive 034*.

The WTC system has the above business rules and edits built in, and the system will not allow the submission of high flow capacity wells unless a multirate test has been conducted. Enforcement action may be a consequence.

However, if a well is clearly within an area for which the ERCB has identified environmental or public/resident issues or where flare restrictions are in effect, industry may, upon written application and approval, be permitted to relax this multipoint test requirement to a single-point test requirement.

3.2 Testing Low Deliverability Gas Wells

Although Section 4.3 of *Directive 040* stipulates that a sandface deliverability relationship is required for all producing gas wells, Section 4.3.4 allows for relaxation from a sandface to a wellhead requirement for wells where the stabilized wellhead absolute open flow potential (AOFP) would be 20 10^3 m^3/d (~710 thousand standard cubic feet per day [mscf/d]) or less and where liquid loading would not mask the well's downhole potential.

The ERCB reiterates that a relaxation from the initial requirement for a sandface deliverability to a wellhead deliverability relationship is permitted for low productivity dry gas wells where the wellhead AOFP is 20 10^3 m^3/d or less (~710 mscfd).

The WTC system permits a wellhead AOFP for low productivity dry gas wells.

3.3 Extended/Transient AOF and Stabilized AOF

Section 4.3 of *Directive 040* clearly states that for the initial deliverability relationship: "A stabilized rate is required to be a calculated value, based on the time to pseudo steady state. This calculation corrects the actual extended test rate to a lower estimated stabilized rate. Higher permeability reservoirs will have very little correction to stabilize, where lower permeability reservoirs will have a large correction. Although the time to pseudo steady state varies with the well geometry and reservoir shape, one can assume a well in the center of a one-section drainage area for a gas well; or if the data or mapping suggests a different drainage area, adjustments must be made as indicated in Section 5 of ERCB *Directive 034*: Gas Well Testing Theory and Practice."

Some confusion has existed as to which deliverability relationship must be reported to the ERCB for an initial test. Often, the most practical and prudent method of conducting an initial deliverability test would involve flowing the well for an extended period of time rather than to complete pressure stabilization. An extended AOF can then be determined, and the stabilized relationship would be derived through calculations using the extended values with reservoir properties obtained from pressure build-up analysis on the well.

The WTC system has business rules and edits requiring both an extended and stabilized deliverability relationship for an initial deliverability test. Without both relationships, the system will not permit the test to be submitted. Enforcement action may be a consequence.

4 Relaxation of or Exemption from Initial Deliverability Testing

The ERCB recognizes that there may be instances where the data obtained from conducting gas well deliverability tests on new wells might be of limited value in relationship to the productivity of those wells or the stage of development and depletion of the reservoirs in which they are completed. *Directive 040* and *Directive 034* provide for relaxation of or exemption from initial well deliverability testing requirements for low productivity gas wells, as described in item 3.3 above.

Section 4.3.4 of *Directive 040* elaborates on other circumstances when a sandface AOF may not be required. Well-established reservoirs for which sufficient deliverability data exist to

correlate well to well flow capacities from geological and reservoir pressure data may be candidates for the relaxation of subsurface testing. In such cases, when initial deliverability test data clearly provide little additional knowledge to the depletion management of the reservoir, licensees are encouraged to apply for relaxation above the standard 20 10^3 m^3/d limit.

Such applications must be made in writing on an individual well or pool basis, with supporting documentation, data, and information to support the exemption request, including the impact of the exemption on conservation and equity and a description of any alternative testing proposal and its appropriateness in meeting the testing intent. A wellhead deliverability relationship with a good initial pressure might be considered an acceptable alternative, but there may be cases when a total exemption from the initial deliverability test might be considered. The ERCB will review and approve applications on an individual case-by-case basis. In no case should approval of such requests be assumed, and unless and until the ERCB does grant approval, all requirements must be met. There is no retroactive approval of testing relaxations.

Directive 040, Section 4.3.5, also allows industry to apply for blanket relaxation or exemption from testing on a regional, formation, or pool basis if it can demonstrate that further well test data provide little future value for the depletion strategy within the region. An application must provide sufficient technical and reservoir engineering analysis to exhibit that further testing is not needed for the depletion strategy within the region.

Industry must be proactive in applying for well testing relaxations or exemptions if deemed reasonable.

A proactive view to an identified need for well test data can be very effective and cost efficient rather than doing the bare minimum of providing a test that is incomplete, inaccurate, and of no value just to meet an ERCB requirement.

5 Inflow Performance Relationships for Flowing Oil Wells

Directive 040, Section 4.3, indicates that there is no deliverability test requirement for oil wells, but where a test such as an Inflow Performance Relationship (IPR) is determined for an oil well, the test data and its interpretation must be filed with the ERCB, as directed by Section 11.120(1) of the *Oil and Gas Conservation Regulations*.

Because flowing oil well IPRs provide essential oil well flow capacity information, it is vital that these data be available for the public record. IPR or any other oil well test data and analysis must be submitted to the ERCB.

The WTC system accepts IPR data for oil wells both in PAS and image file format. IPR data taken but not submitted would place the licensee/operator in noncompliance.

6 Well Fluid Analysis Requirements

Directive 040, Section 3.5: Gas and Fluid Analysis, provides specific requirements for the collection and submission of fluid analyses, including both gases and liquids. Fluid analyses are particularly important, as they are the source of sour gas concentrations that are used in many of the initiatives of PS&SG and in business processes related to the public safety of Albertans.

The ERCB requires that samples of all fluids (gas, oil, bitumen, and water) be collected, analyzed, and submitted in accordance with the requirements stated in *Directive 040*, Section

3.5, as well as in Clause 11.070(2) of the *Oil and Gas Conservation Regulations*. In particular, note that a gas analysis must be submitted to the ERCB within 90 days of placing a well on production for all wells that, when completed, are not within an existing pool as defined by an ERCB Pool-Order. In addition, if a well produces both gas and condensate, a recombination analysis must be submitted.

With the implementation of the WTC system, industry is required to include a gas analysis PAS file to meet the initial deliverability testing requirements for all new undefined gas wells. New wells completed in a clearly defined and developed pool may submit a representative analysis from an adjacent well if written justification is provided with the test. Not meeting this submission requirement will be considered noncompliance.

The ERCB does not expect the submission of fluid analyses taken on a frequent basis (monthly) for metering/measurement calibrations for monthly production reporting volumes unless the composition of the reservoir fluids has changed. However, it is good practice to conduct and provide at least two fluid samples, which could provide a better compositional average than just one analysis.

7 Current PAS File Formats

Current PAS file formats are available from the ERCB Web site through the following links

- Excel file
- PDF file

Appendix B: Reference Material

Oil and Gas Conservation Regulations

Directive 005: Calculating Subsurface Pressure via Fluid-Level Recorders–SI Units

Directive 007: Production Accounting Handbook

Directive 019: ERCB Compliance Assurance—Enforcement

Directive 034: Gas Well Testing Theory and Practice

Directive 038: Noise Control Directive–User Guide

Directive 056: Energy Development Applications and Schedules

Directive 060: Upstream Petroleum Industry Flaring, Incinerating, and Venting

Directive 065: Resources Applications for Oil and Gas Reservoirs

ERCB IL 83-1: Reservoir Limit Tests on Discovery Oil Wells: A Guide

Appendix C: Well Test Contact List

ERCB WEB SITE LINKS:

ERCB Home Page:

www.ercb.ca

Well Test Electronic Data Capture:

ERCB Home : Industry Zone : Rules, Regulations, Requirements : Well Testing

Annual Subsurface Pressure Survey Schedules and Outstanding Initial Pressure, Deliverability, DST, Gas and Fluid Analysis Listings:

ERCB Home : Industry Zone : Rules, Regulations, Requirements : Well Testing - Pressure Survey Schedules

CONTACT PHONE AND E-MAIL

All well testing enquiries; including initial or annual requirements, PAS file submission error tracking, questions, problems or concerns:

Welltest-helpline@ercb.ca

403-297-6925 (Well Test Helpline)

DDS (Digital Data System) support such as system error tracking, creating initial company accounts, or changing corporate administrator access,

DDSSupport@ercb.ca

403-297-5802 (DDS Administrator)

Information Services Enquiries (data dissemination and sales):

infoservices@ercb.ca

403-297-8311 (Order Desk)

ATTACHMENT I

SAMPLE LETTER FOR COORDINATING OPERATORS

(as per Section 4.5.5 of this directive)

(Date)

(Company Name and Address)

OR

To All Operators of the _____ Pool

Dear Sirs:

20XX SUBSURFACE PRESSURE SURVEY REQUIREMENTS

_____ POOL

The Energy Resources Conservation Board (ERCB) has designated _____ (*company name*) the responsibility of coordinating pressure survey requirements for the above pool, as listed in the current annual survey schedule. In accordance with ERCB *Directive 040: Pressure and Deliverability Testing Oil and Gas Wells*, _____ (*number*) well(s) must be surveyed this year.

To determine the best plan for this pool considering survey quality, areal coverage, and cost, we are requesting all pool operators to review their operations and submit possible candidates, acceptable methods and timing for surveying. We hope that this will enable us to gather quality data for reservoir evaluation and management at a reasonable cost while minimizing production losses.

Please contact the undersigned at _____ by (*date)* with your information.

Yours truly,